EPA – UNDERGROUND INJECTION CONTROL PERMIT APPLICATION NO. ID2D001-A

Applicant: Snake River Oil and Gas, LLC
Well Name: DJS Properties #2-14

Table of Contents

EPA – UNDERGROUND INJECTION CONTROL PERMIT APPLICATION ATTACHMENTS

ATTACHMENT A: Area of Review

AREA OF REVIEW - 40 CFR 146.6 requires that the area of review (AOR) for each injection well or each field, project or area of the State be determined per either paragraph (a) or (b) of the regulation. Based on the remote location of the well and the lack of potential pathways which may cause the migration of the injection and/or formation fluid into an underground source of drinking water, Snake River Oil and Gas LLC has adopted the ¼ mile fixed radius to define the project AOR provided for in the regulations (i.e., 40 CFR 146.6(b)). Specifically, the AOR for this application encompasses a ¼ mile radius circle from the wellbore.

ATTACHMENT B: Maps of Well/Area and Area of Review

Within the Area of Review:

There are no producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface or subsurface), quarries, residences, or roads. There are no drinking water wells or springs within the area of review.

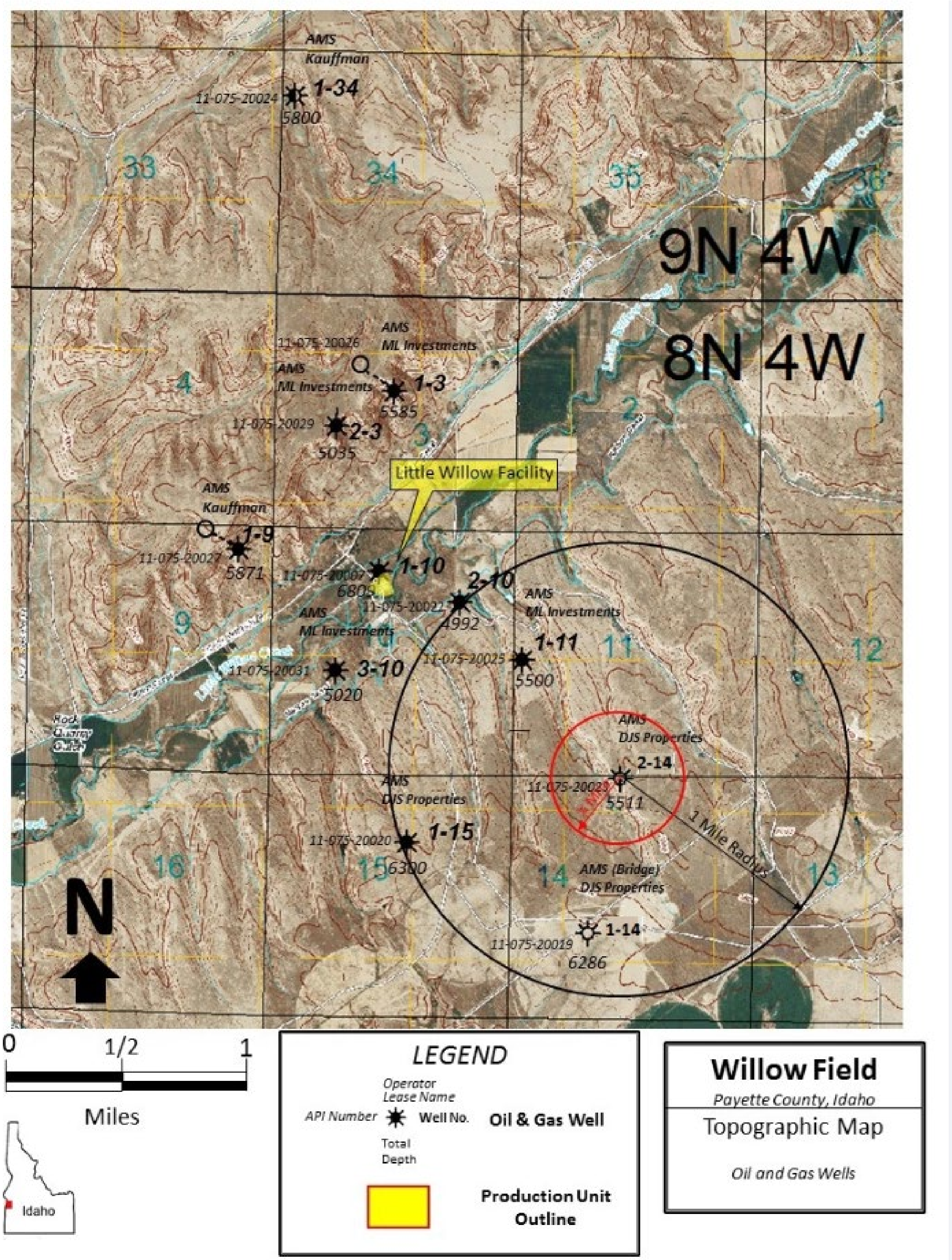
Within one Mile of the Property Boundary:

There are no intake and discharge structures, nor hazardous waste treatment, storage, or disposal facilities. There are not existing injection wells.

B-1 Topographic Map of Well/Area and Area of Review

A. TOPOGRAPHIC MAP OF WELL/AREA AND AREA OF REVIEW - There are no notable wells, springs, water bodies, etc. within the 1/4 mile radius Area of Review. This area is the Willow Oil and Gas Field, existing oil and gas wells are shown on the map. Produced oil, gas, and water flows through existing flowlines and is collected at the Little Willow Facility (Att. B-3)

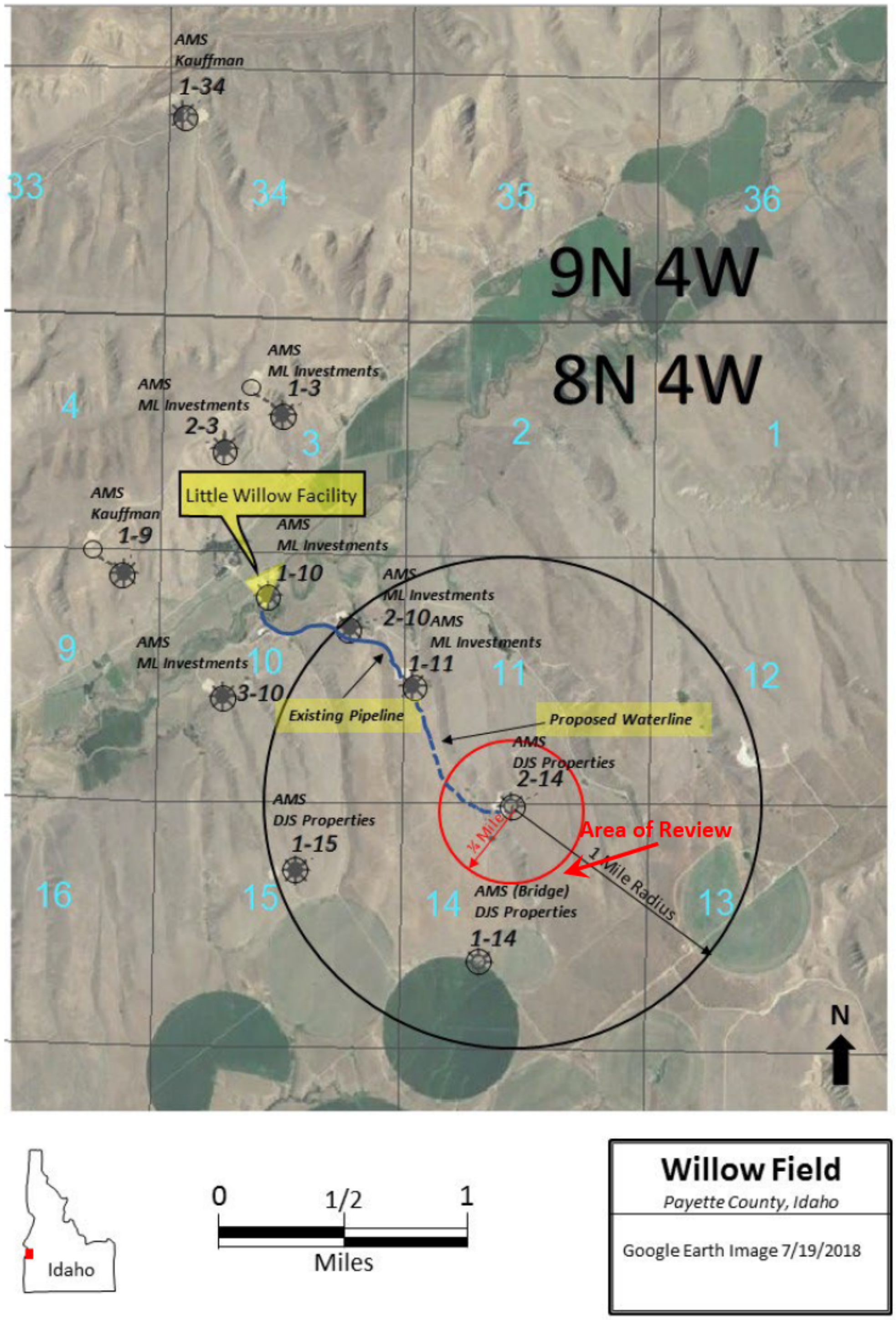
B-2



Google Earth Image of Area of Review

Note: AMS wells operated by Snake River Oil and Gas as of 1-2020

MAPS OF WELL/AREA AND AREA OF REVIEW - Google Earth Image of Area of Review. The aerial photo below shows the existing flowline from the Little Willow Production Facility as well as the proposed flowline which extends from the ML Investments #1-11 well site to the DJS Properties #2-14 well site (proposed water injection site).



Note: AMS wells operated by Snake River Oil and Gas as of 1-2020

B-3 Google Earth Image of Little Willow Production Facility (LWPF)

MAPS OF WELL/AREA AND AREA OF REVIEW - Google Earth Image of Little Willow Production Facility (LWPF). The LWPF collects raw production via pipelines from area wells: separates oil, condensate, natural gas, and water. Storage tanks for liquids. Water is currently hauled out by truck.

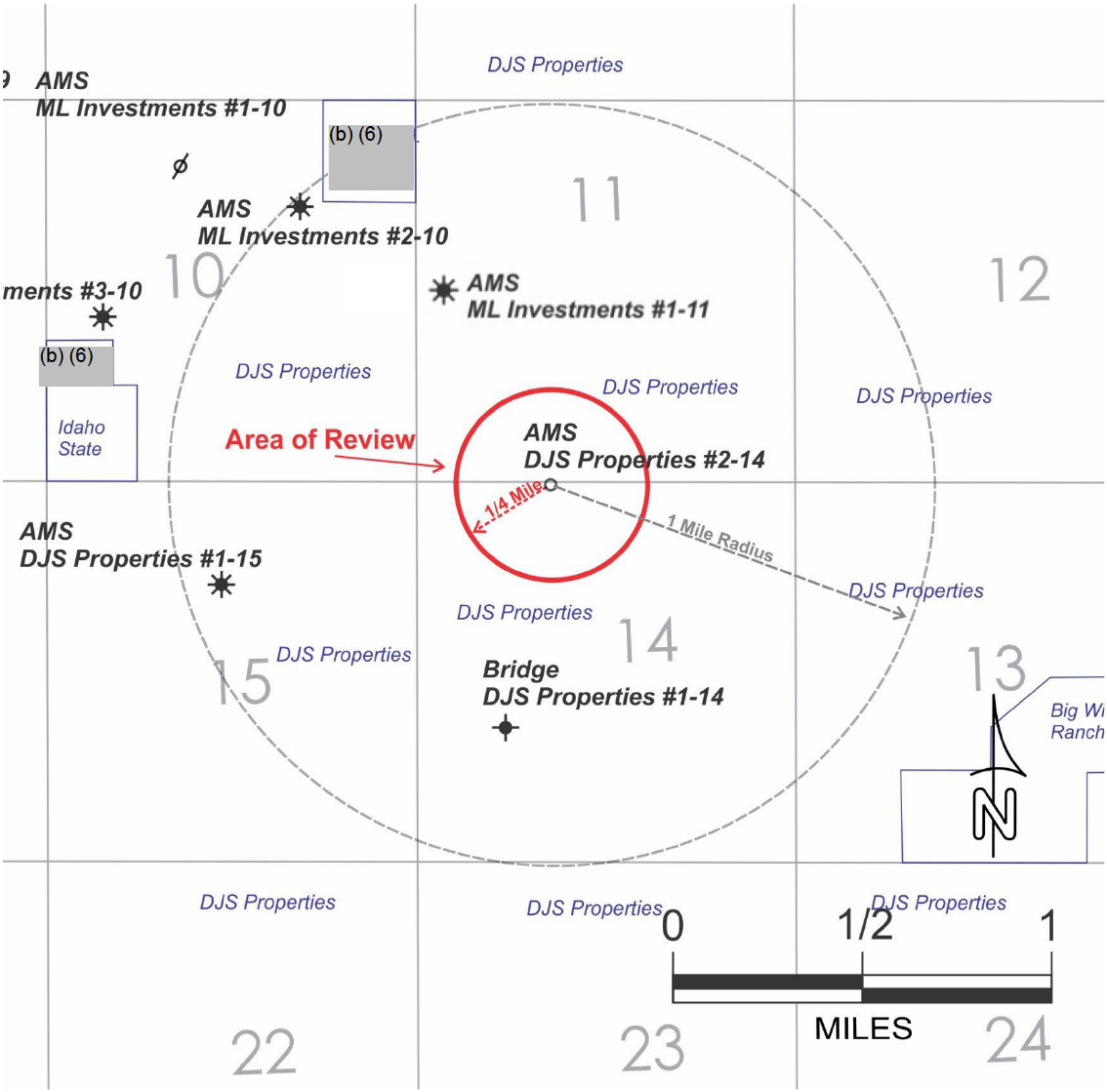
Google Earth Image 7/19/18

B-4 Google Earth Image of DJS 2-14

MAPS OF WELL/AREA AND AREA OF REVIEW – Google Earth Image of DJS #2-14 Well Pad, the proposed injection well.

Google Earth Image 7/19/18

Property Ownership Map for Area of Review. 100% of the property within the area of review is owned by DJS Properties.

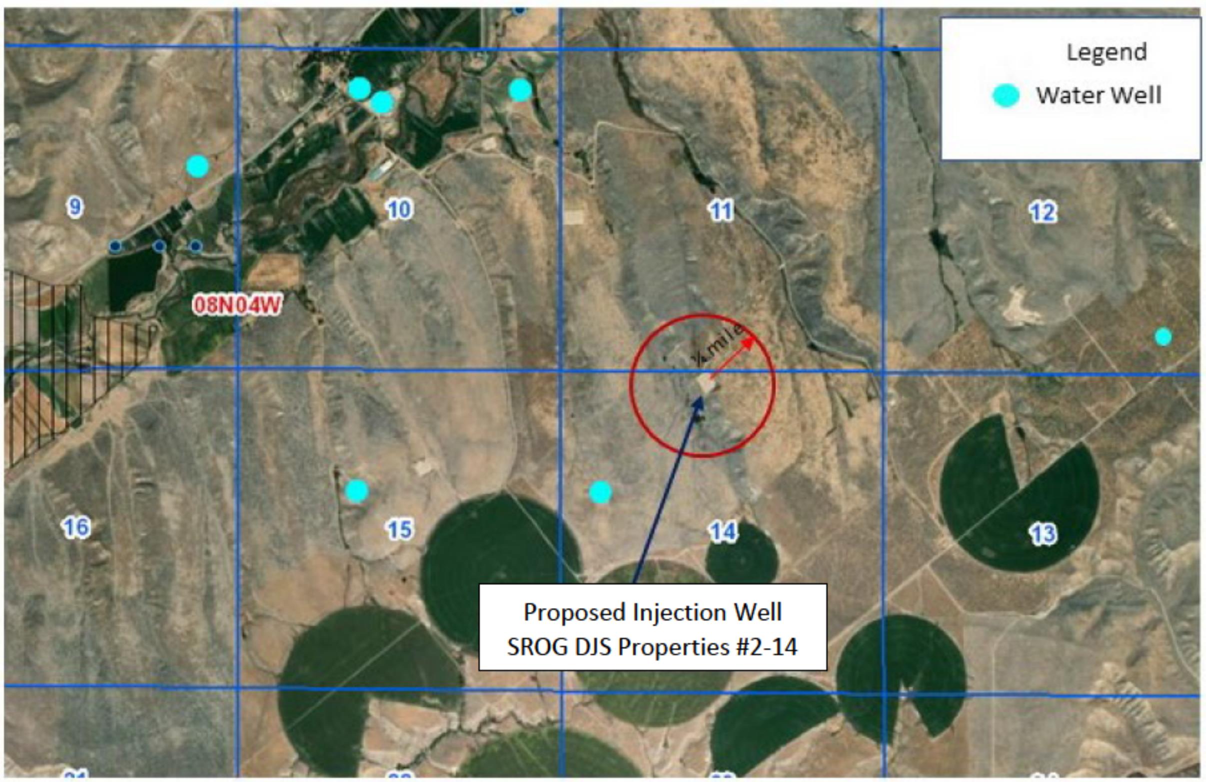


Note: AMS wells operated by Snake River Oil and Gas as of 1-2020

ATTACHMENT C: Corrective Action Plan and Well Data

CORRECTIVE ACTION PLAN AND WELL DATA - There are no water wells within the area of review.

There are no additional existing producing wells, abandoned wells, injection wells, or wells of any type that intersect the proposed injection zone within the Area of Review, other than the proposed injection well DJS #2-14.



Ggeogle Earth Areal Image
Idaho Department of Water Resources – Idaho.gov

E. NAME AND DEPTH OF UNDERWATER SOURCES OF DRINKING WATER (USDW) (CLASS II)

Geologic Data on Shallow Aquifers, and Injection and Confining Zones

[1]Spencer H. Wood, PhD. PG
Consulting Geologist
June 17, 2019

Sediments above the proposed injection zone (4,910-5,500 ft depth in DJS 2-14) are ~2,000 ft of the lacustrine mudstone/claystone Chalk Hills Formation, overlain by 860 ft of mudstone/claystone of the lower Glenns Ferry Formation (**Figs. E-1 and E-2**). The upper Glenns Ferry Formation (above 1,410 ft depth) is dominantly mudstone/claystone, but contains several fine-sand units 10-50 ft thick regarded as stacked turbidite sands within prodelta mudstones. The "Digital Files for Injection Permit and Appendices" folder has digital files for these figures.

An uppermost sand unit identified as the Pierce Gulch sand (Wood, 2004) occurs in the surrounding hills above 2,400 ft elevation where it is up to 250 ft thick. In the Willow field area the Pierce Gulch sand appears to be < 100 ft thick and may be absent most wells. In the 185-ft deep (b) (6) domestic well ~1.7 miles northwest of DJS 2-14 (**Fig. E-1**), the upper 161 feet is described as claystone and siltstone, with sandstone from 161-185 ft depth (**Appendix E**, Hydrologic, Inc., 2014, Figure 5). This well is likely in the prodelta sands and not in the Pierce Gulch sand. Other water wells are in the shallow alluvium of Little Willow Creek.

We did a very complete water flow testing and water analysis of two existing wells in this area prior to our developing Willow Field. This was to establish "baseline" levels of any contaminants already in the water shed. One of these reports ((b) (6) well) is attached in **Appendix E**.

Three miles south of the proposed DJS 2-14 injection well, the regional SW dip and minor faulting places the base of the Pierce Gulch sand down to elevation ~1,600, where it is ~600 ft thick (**Fig. E-2**). In these wells to the south (Johnson #1, Daws #1, Espino 1-2) the Pierce Gulch sand is the important sand aquifer that occurs over much of the western plain to the south at similar depth and elevation (Wood, 1994).

The turbidite sands within the underlying prodelta mudstones are discontinous aquifers that are rarely developed as a water supply because of depth. The upper Glenns Ferry Formation is interpreted as a regressive unit comprised of a delta-prodelta sequence prograding to the southwest in response to lowering lake levels as the lake drained 3 to 2.5 Ma ago

The lower Glenns Ferry Formation is interpreted as a transgressive lacustrine mud, as Pliocene Lake Idaho filled during the late Miocene (Wood, 1994; Barton, 2019). No sands are within these muds in the Willow field area, and logs show very low (~ 1 ohm m) monotonous resistivity typical of clay-rich mudstones.

Contact of the lower Glenns Ferry Formation mudstones with the underlying thick mudstones of the Chalk Hills Formation has no identifying characteristic on resistivity logs. Resistivity is continually low downward without a break. The contact is difficult to recognize in field mapping of exposures 3.2 miles to the northeast. In exposures "the Chalk Hills Formation is typically more massive than the Glenns Ferry Formation, lighter in color, and contains more clay (likely bentonite). Soils typically have medium to small surface cracks of expansive clays" (Lewis et. al. in preparation, 2019). In the DJS 2-14 well the contact is chosen on density logs at 2,380 ft depth where density increases from 1.95 to 2.05 g/cm3 at and then increases monotonically downward to 2.27 g/cm3 at 4,300 ft depth (**Fig. E-2**). The abrubt increase suggests an unconformity with the underlying, slightly denser mudstone. The monotonic downward increase in density is characteristic of increasing claystone compaction with depth. The contact is also expressed by a downward increase on the gamma log from 75 to 90 API.

Beneath the ~2,000' thick mudstone/claystone of the Chalk Hills Formation, the mudstone section is invaded by a 120-ft thick basalt sill (4,370-4,490 ft depth)(**Fig. E-2**). Several basalt sills are in the deep section imaged by 2D and 3D seismic, occurring as saucer shaped lenses extending laterally up to one mile. Mudstone continues down to 4,910 ft depth, below which is the Willow sand section of the proposed injection zone (4,910-5,500 ft). These sands were called sands of the lower Chalk Hills Formation, but in a new interpretation by Barton (2019), the sill and all sediments below 4,320 ft are regarded as the Payette Formation, an older, middle Miocene fluvial-lacustrine unit unconformably overlain by the Chalk Hills Formation. In outcrop ~10 miles east of DJS 2-14, the Payette Formation is quite tuffaceous with thick (> 100 ft) bentonitic clay layers, rare arkosic sand units, and characteristically has steeper dips of ~15° south. Regardless of the formation assignment, the injection zone Willow sands are clearly overlain by the 2000 ft thick Chalk Hills mudstone/claystone, an additional 860 ft of lower Glenns Ferry mudstone/claystone, and occur in the isolated fault block in the vicinity of proposed injection well DJS 2-14.

References

Barton, M. 2019. Neogene lacustrine systems and sequence stratigraphy of the western Snake River Basin. ppt presentation. Idaho Geological Survey, 41 pages.

Hydrologic, Inc., 2014. Measurement and sampling of the (b) (6) Domestic well. Report to Alta Mesa Services, LP. 34 pages.

Lewis, R., Feeney, D., Wood, S.H., Breedlovestrout, R. in preparation-2019. Geologic Map of the Sheep Ridge 7.5-minute Quadrangle, 1:24,000. Idaho Geological Survey, Moscow, Idaho.

Wood, S.H., 1994. Seismic expression and geological significance of a lacustrine delta in Neogene deposits of the western Snake River Plain, Idaho: American Association of Petroleum Geologists Bulletin, v. 78, p. 102-121. internet:

https://pdfs.semanticscholar.org/3a7a/e47722b59de87c78e83bd2eeb7656338a997.pdf

Wood, S.H. 2004. Geology across and under the western Snake River Plain, Idaho: Owyhee Mountains to the Boise Foothills (Chapter 7). in Haller, K.M. and Wood, S.H. (eds.), Geological Field trips in southern Idaho, eastern Oregon, and Northern Nevada. U. S. Geological Survey Open-File Report 2004-1222. p. 84-107. Internet: http://pubs.usgs.gov/of/2004/1222.

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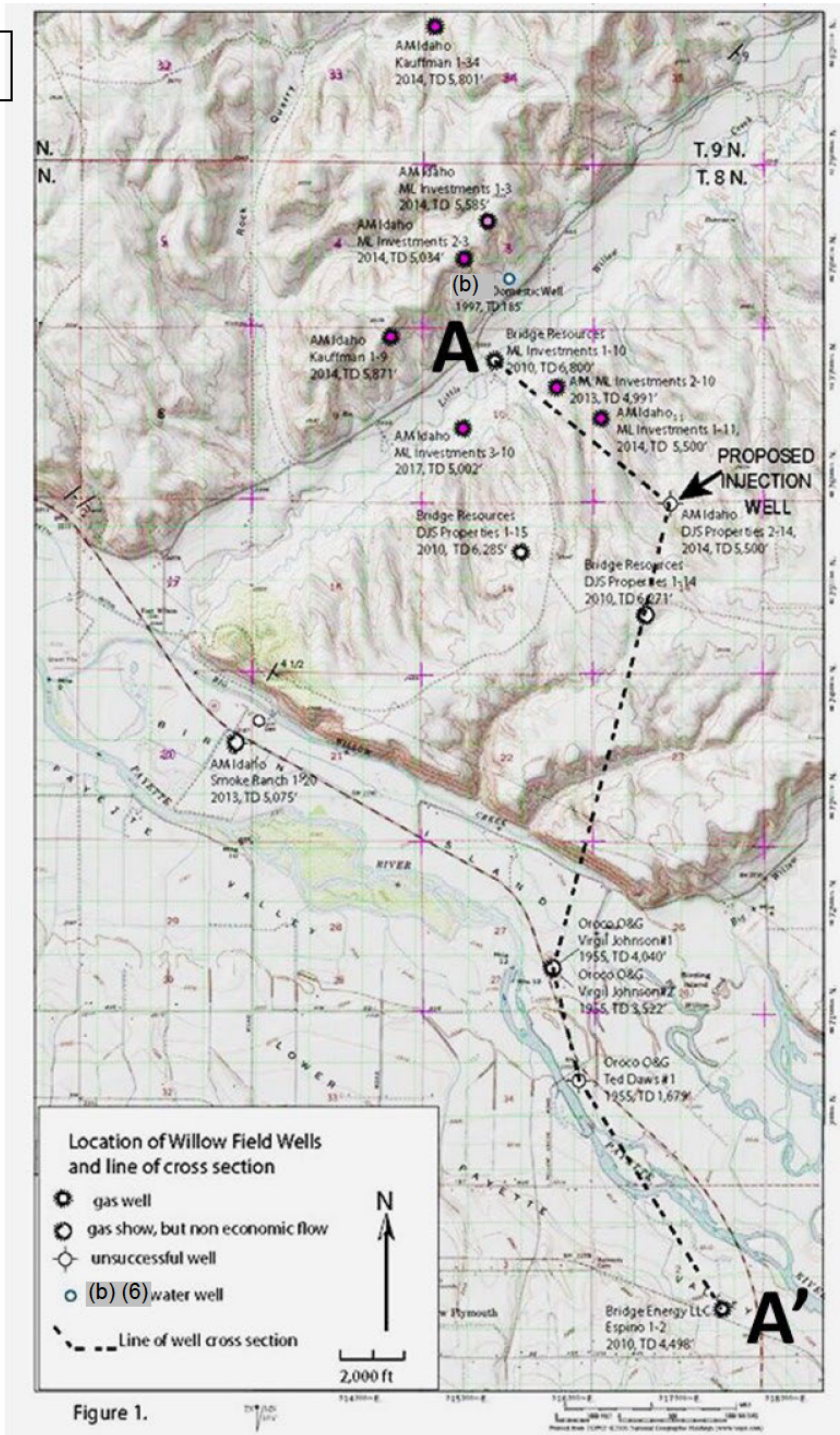
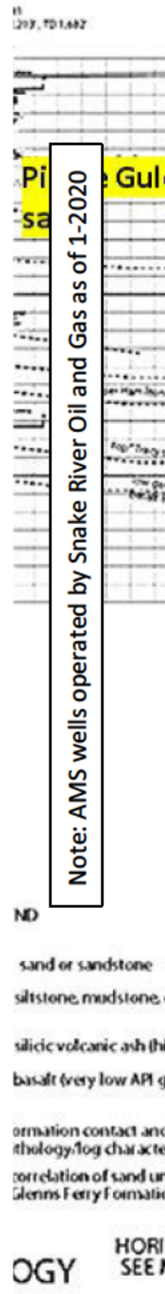
[1]Spencer Wood is an emeritus professor of geology and geophysics at Boise State University. Education is a degree in Geophysical Engineering from Colorado School of Mines, 1964; MS in geophysics, 1972 and PhD in Geology from Caltech 1975. Former positions with Mobil Oil International, US Geological Survey and visiting professor at University of Oregon, Chiang Mai University-Thailand and National University Singapore. Research on regional geology and geophysics, neotectonics, volcanology, borehole geophysics, hydrogeology and geomorphology. Consulting for Los Alamos National Laboratory, United Water Idaho, Inc., Idaho Dept. Water Resources, Simplot Foods, Hydrologic, Inc., Alta Mesa LP, Thailand Dept. Water Resources, Thailand Dept. Energy Development. Registered Professional Geologist-Idaho No. 616.

E-1 Location of Willow Field Wells and line of Cross Section Map

Figure E-1





Note: AMS wells operated by Snake River Oil and Gas as of 1-2020

Figure E-2

ATTACHMENT G: Geological Data on Injection and Confining Zones (Class II)

G. GEOLOGICAL DATA ON INJECTION AND CONFINING ZONES (Class II) - In the DJS Properties 2-14 well the proposed injection zone is in the Willow Sand, which is dominantly composed of several hundred feet of massive porous and permeable quartz rich sandstones. The massive sandstones also contain minor thin shaly sandstone and claystone layers which vary in size both vertically and laterally in the section **(See *Figure G-1*)**. G-1 is a composite lithologic type log of the DJS #2-14 from the surface to its total depth of 5500', then the deeper section is added on from the ML #1-10 well, which penetrated the deeper section of the Willow Sands. Per well log correlation the top of the injection zone occurs at 4,910' TVD and is 590' in gross thickness (5,500' Well TD). The confining zone is both the overlying Glenns Ferry Formation and the upper and middle Chalk Hills formation. These formations are very widely distributed in this basin and are typically very impermeable clays. In the DJS Properties 2-14 well the Glenns Ferry formation (approx. 250'-2380' TVD) is composed of highly impermeable lacustrine Claystone, as well as scattered arkosic sandstones. The upper and middle Chalk Hills formation (approx. 2,380'-4,910'TVD) contains more lacustrine clays, silicic volcanic ash, and basalt.

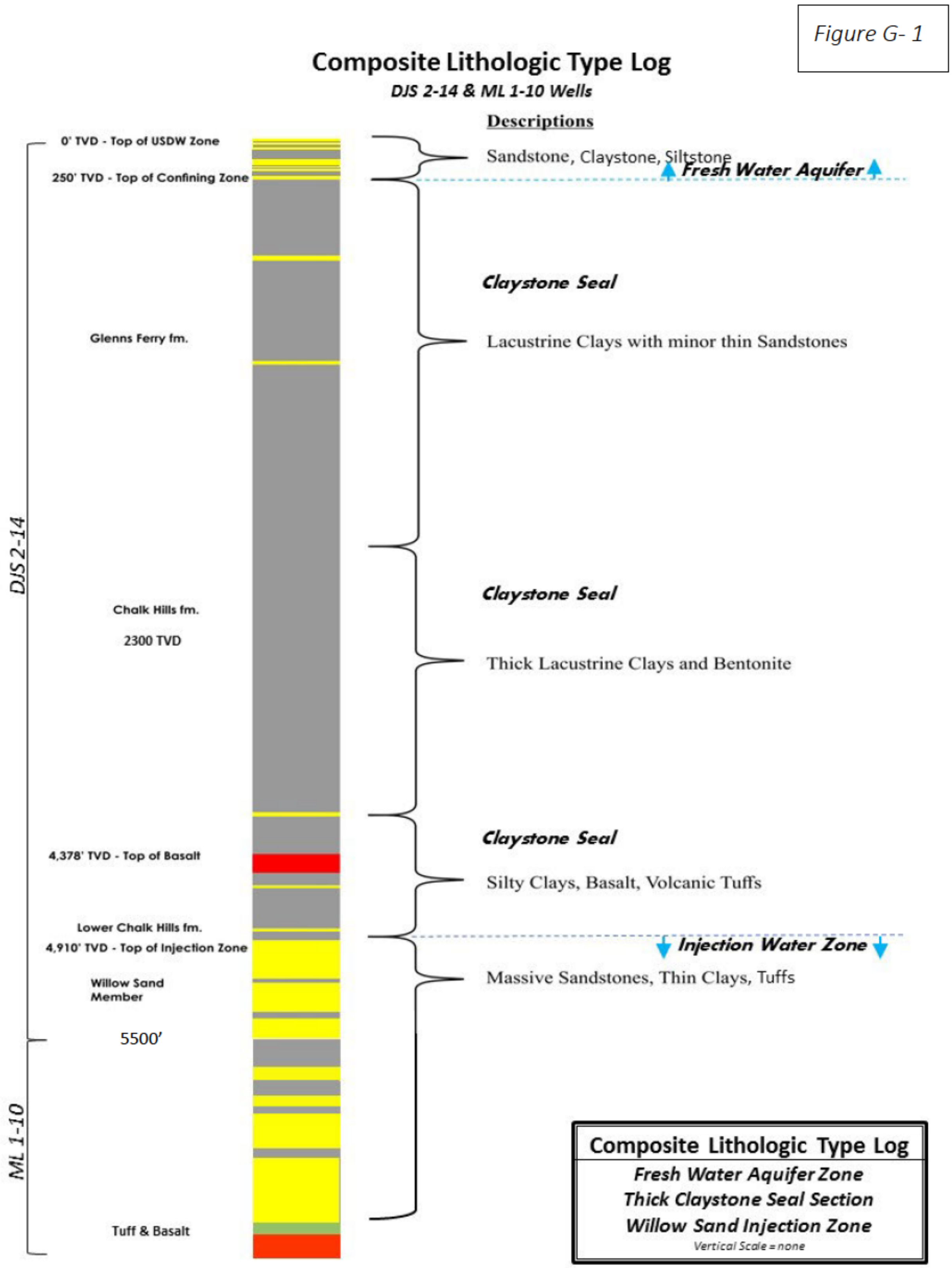
The Willow Sands are a thick section of Miocene age lacustrine and fluvial sands deposited in a gradually subsiding basin. The Western Snake River Basin (WSRB) began rifting and subsiding in middle Miocene time, coincident with and following eruption of the Columbia River Basalts (17 – 12 MYA). Basalts were extruded, and volcanic ash and marsh sediments were laid down as the basin continued to subside. As the basin deepened, a lake (Lake Idaho) was formed and fluvial sands and sediment washed into and continued filling the basin. The Payette Formation and the Willow Sands member of the lower Chalk Hills formation represent these early sediments. As the basin continued to subside, drainage outlets were blocked allowing a lake of great depth (over 1000 feet in depth) to form. The middle and upper Chalk Hills formation represent this phase of deposition, it is composed of 2,000' to 3500' of claystones and ash. See **Figure G-2 and Figure G-3** modified from Barton, Idaho Geologic Survey, 2019 (pre-publication). **Figure G-2** is a location map over the northeast margin of the basin. ***B-B'*** indicates a line of cross-section from near the basin margin on the east, then westerly across the Willow Field and into the basin. **Figure G-3** is the regional cross-section ***B-B'*** which incorporates the exploratory wells drilled and demonstrates the geologic history described above. The salient points demonstrated here relative to this injection well discussion are these:

1. Thick Chalk Hills claystones provide a widespread and extremely competent series of top-seals above the Willow Sands.
2. The small faults present locally are early, syn-depositional and die out (cease movement) in the overlying Chalk Hills claystones.
3. The shallow aquifers in use in the basin are separated from the Willow Sands at depth by thick Chalk Hills and Glenns Ferry claystones.

An important point to note is that because these Chalk Hills and Glenns Ferry clays are lacustrine (deposited in a lake), they are uniformly widespread, and also very thick. Because the clays and tuffaceous clays are soft, they make very impermeable and competent confining layers.

Local wells drilled deeper than the DJS 2-14 show that the Willow Sands can be 1500' to 2000' thick (ML 1-10). Underlying the Willow Sands and interbedded with the lower sands are ash beds, tuffaceous claystones and basalts, these can provide competent confining layers. **Figure G-4** is a regional base map which shows the DJS 2-14 and logs from several surrounding wells. Subsequent figures **(G-5 thru G-9)** are larger scale versions of these well logs. Note that the conforming overlying claystone zones are from 2,400' to 3,600' thick in these wells. Digital files for the open hole logs and mud logs of each of these wells are available in the "Digital Files for Injection Permit and Appendices" folder.

G-1 DJS 2-14 Composite Lithological Section



G-3 Regional Geologic Cross-Section Demonstrating Widespread Claystone Seal

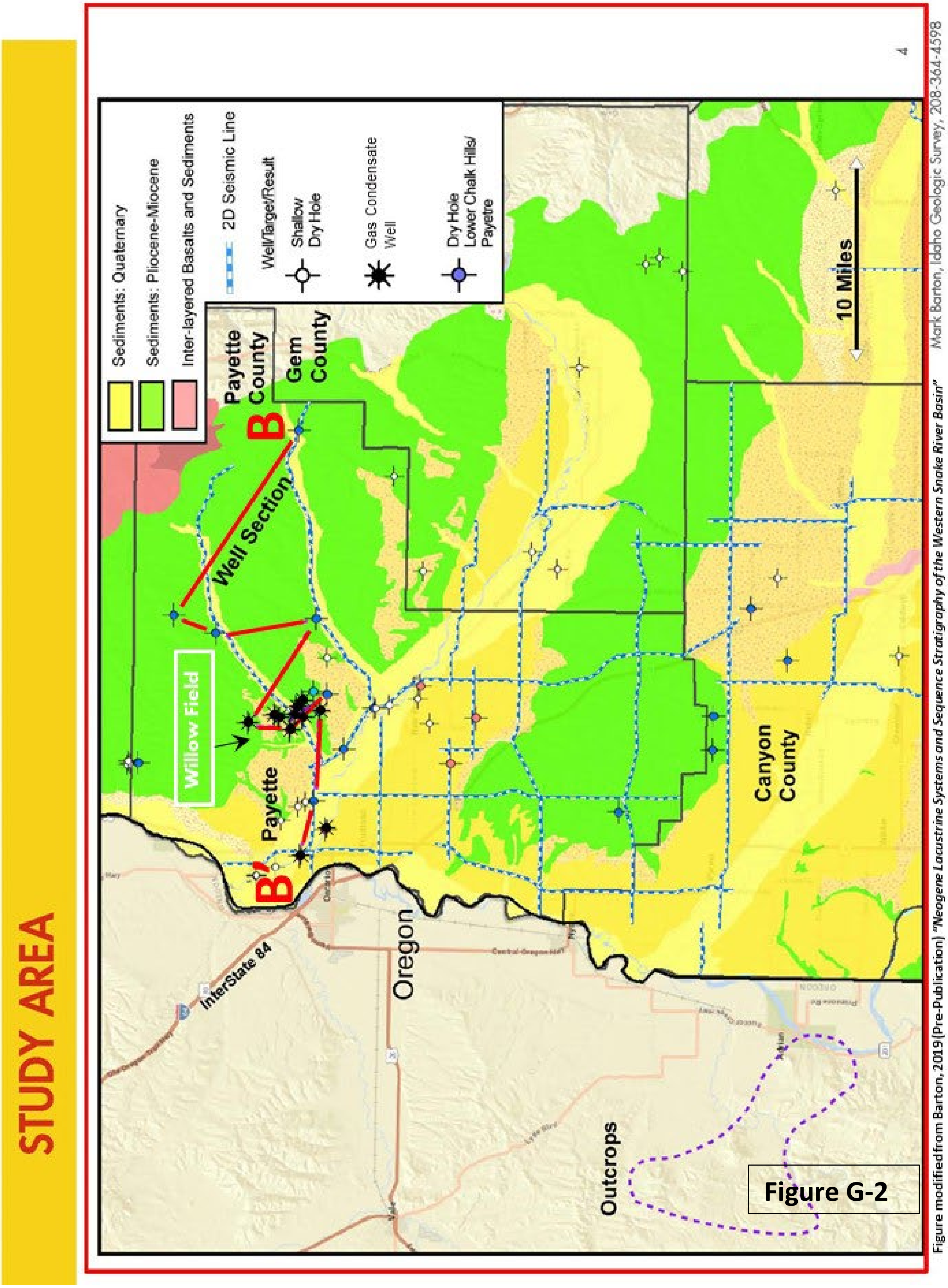


Figure G-2

Mark Barton, Idaho Geologic Survey, 208-364-4598

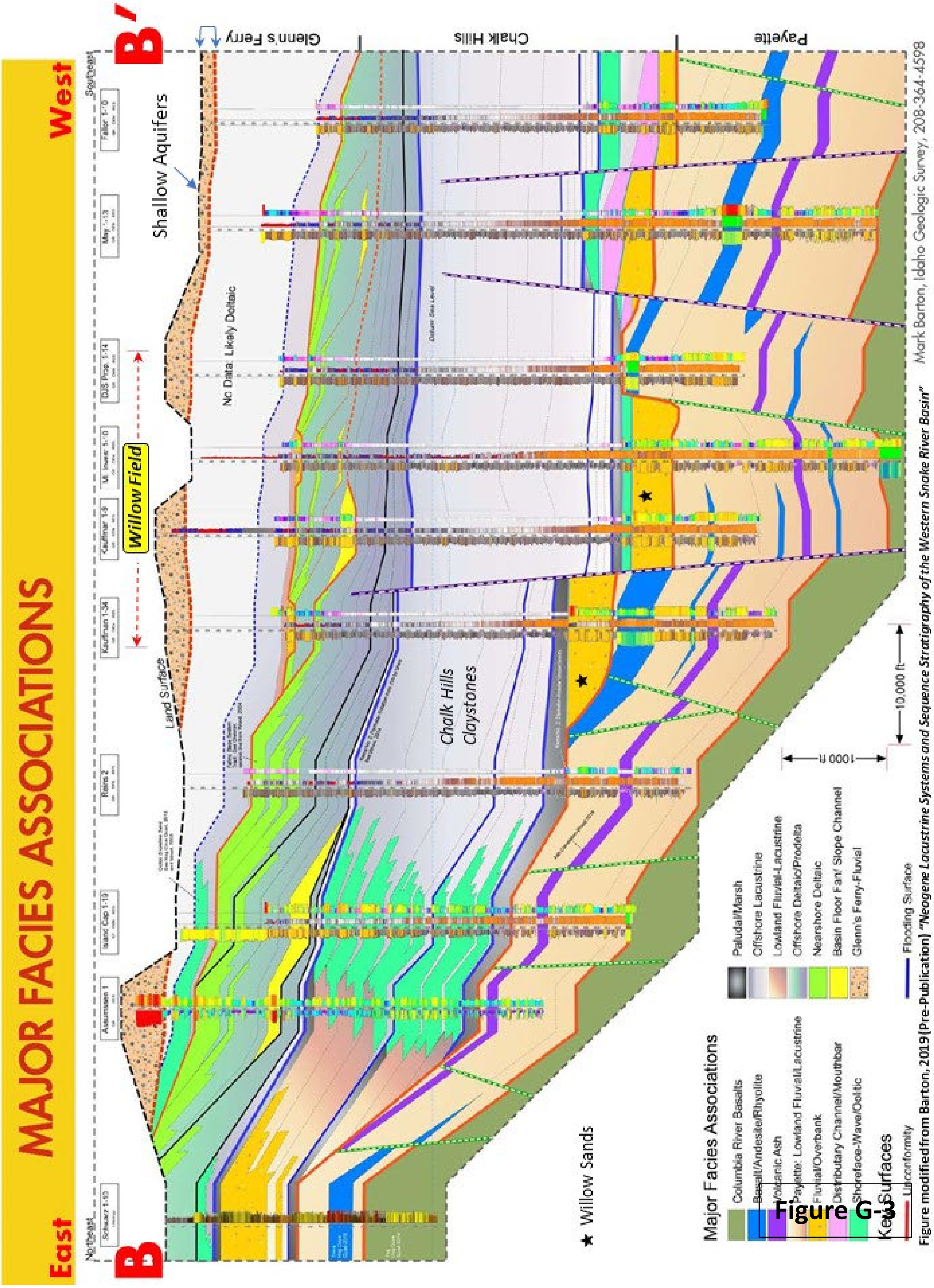
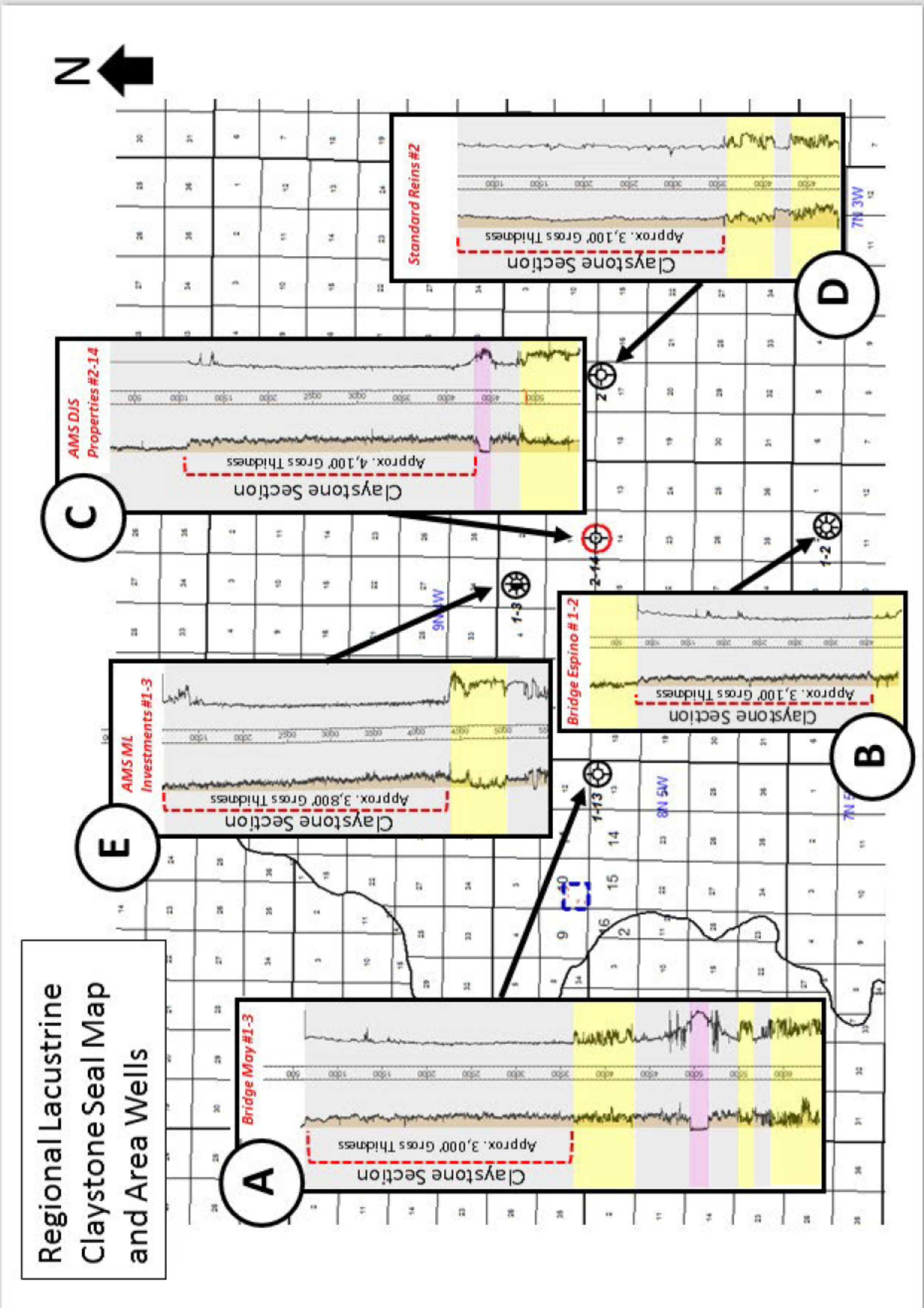


Figure G-3

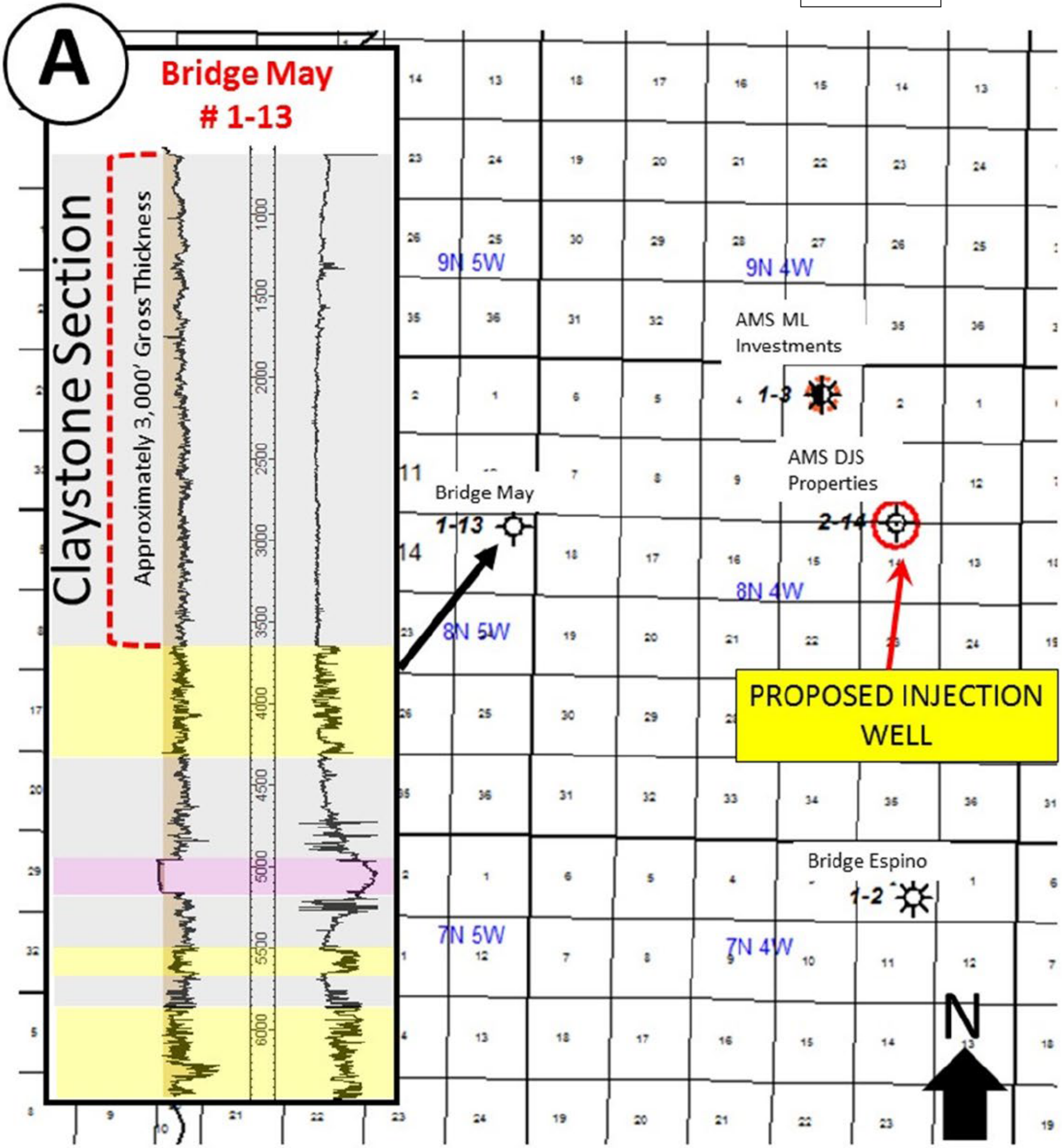
G-4 Regional Lacustrine Claystone Seal Map (Figures G4 – 9)

Figure G- 4



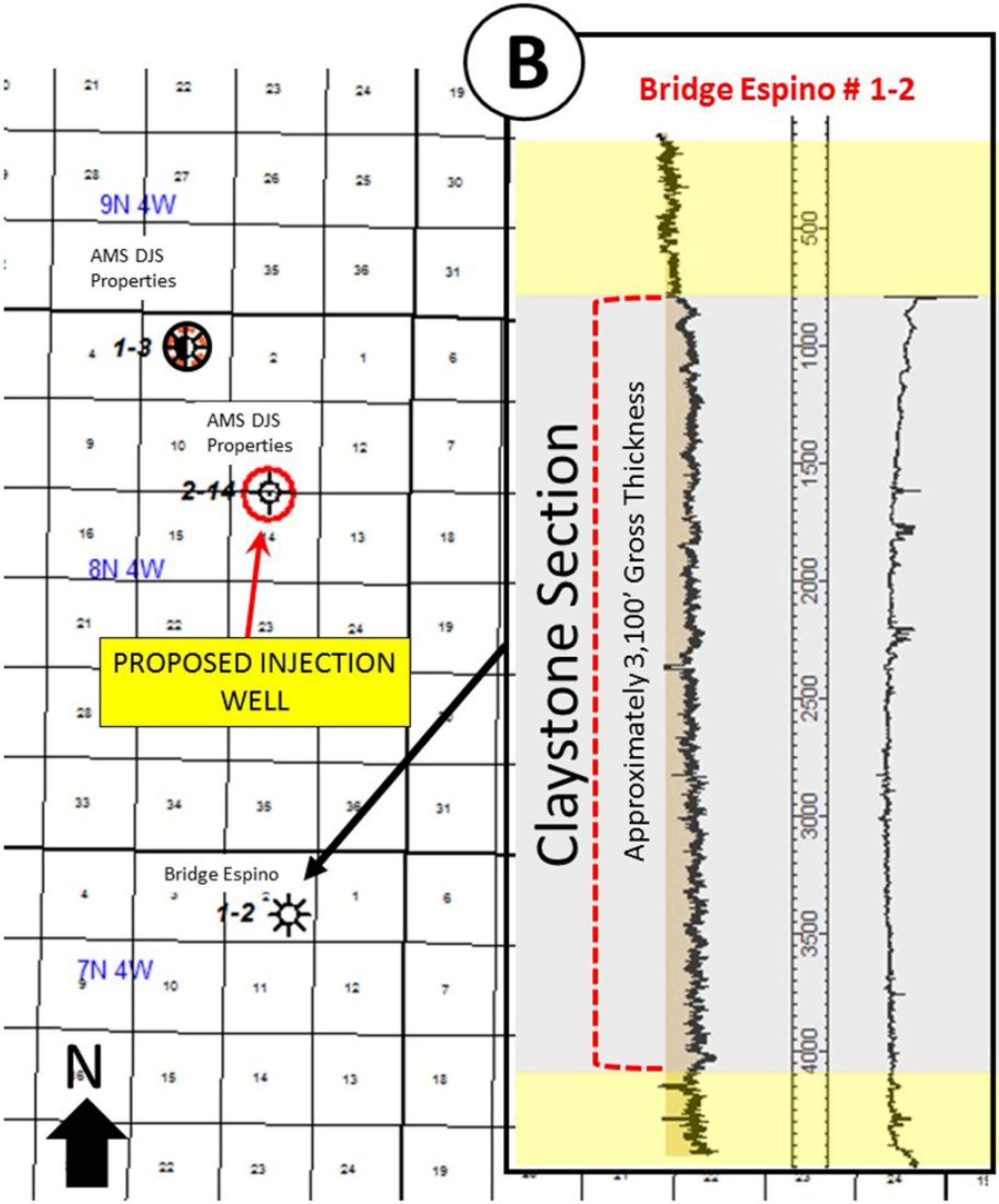
Note: AMS wells operated by Snake River Oil and Gas as of 1-2020

Figure G- 5



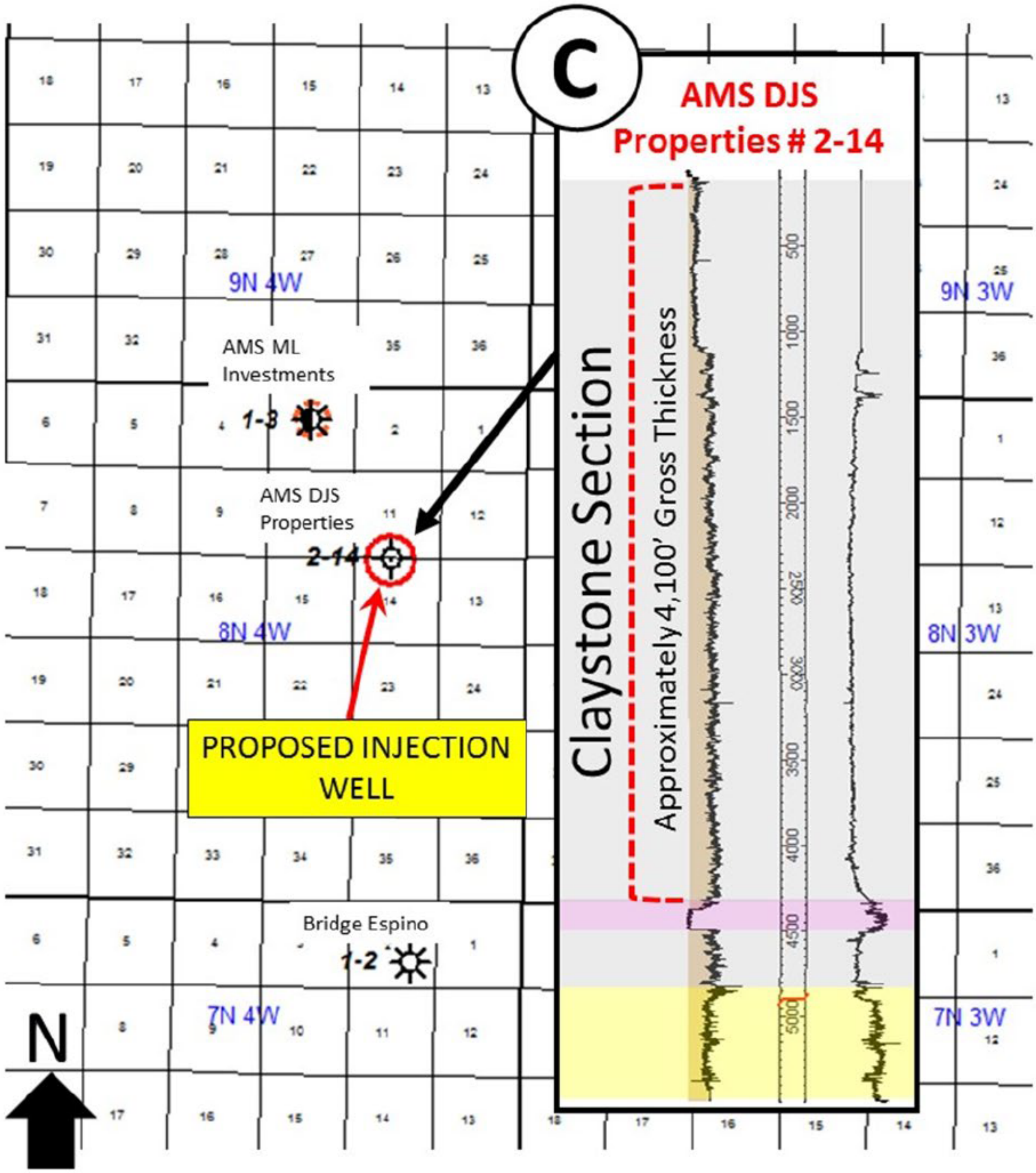
Note: AMS wells operated by Snake River Oil and Gas as of 1-2020

Figure G- 6



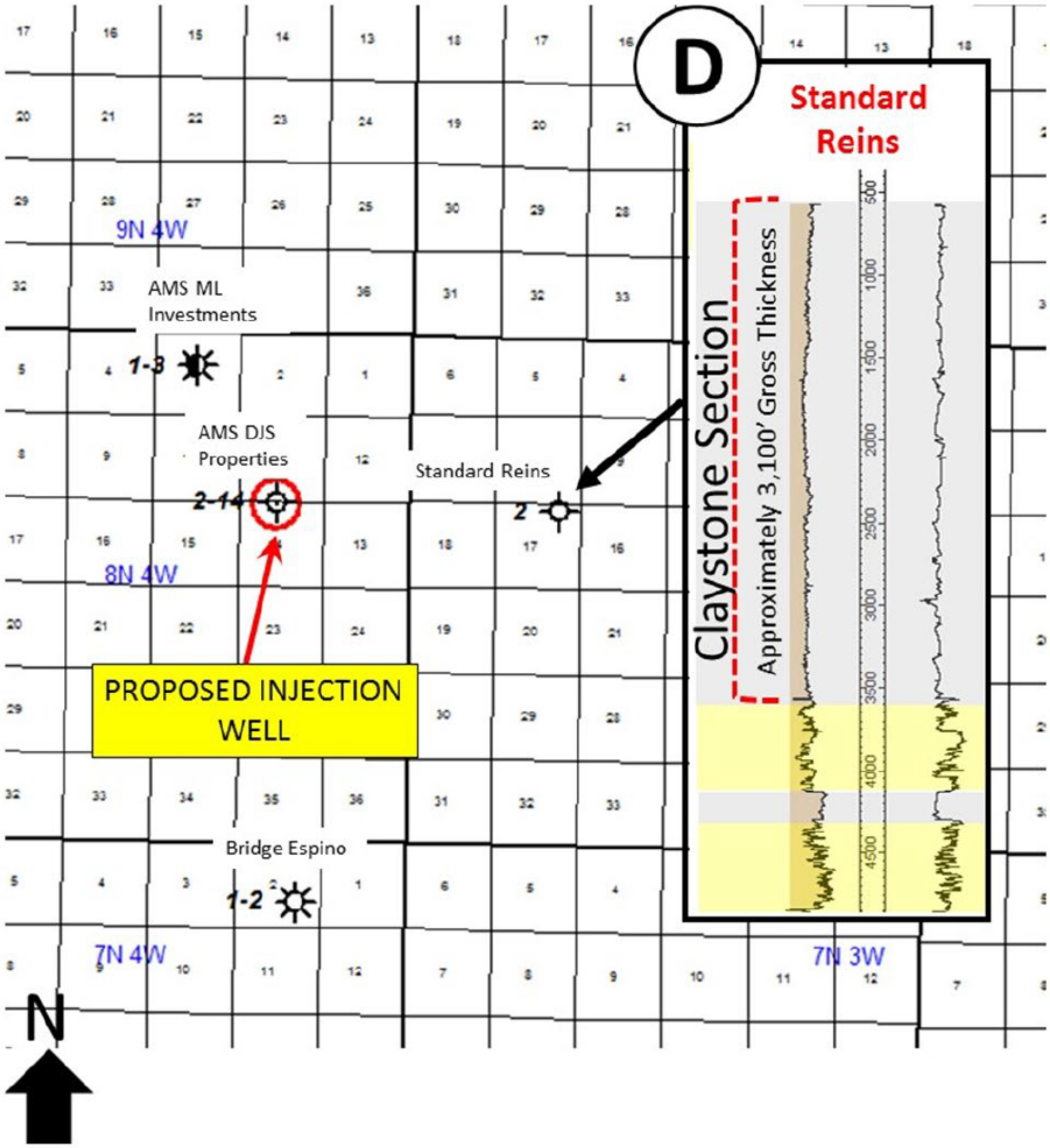
Note: AMS wells operated by Snake River Oil and Gas as of 1-2020

Figure G- 7



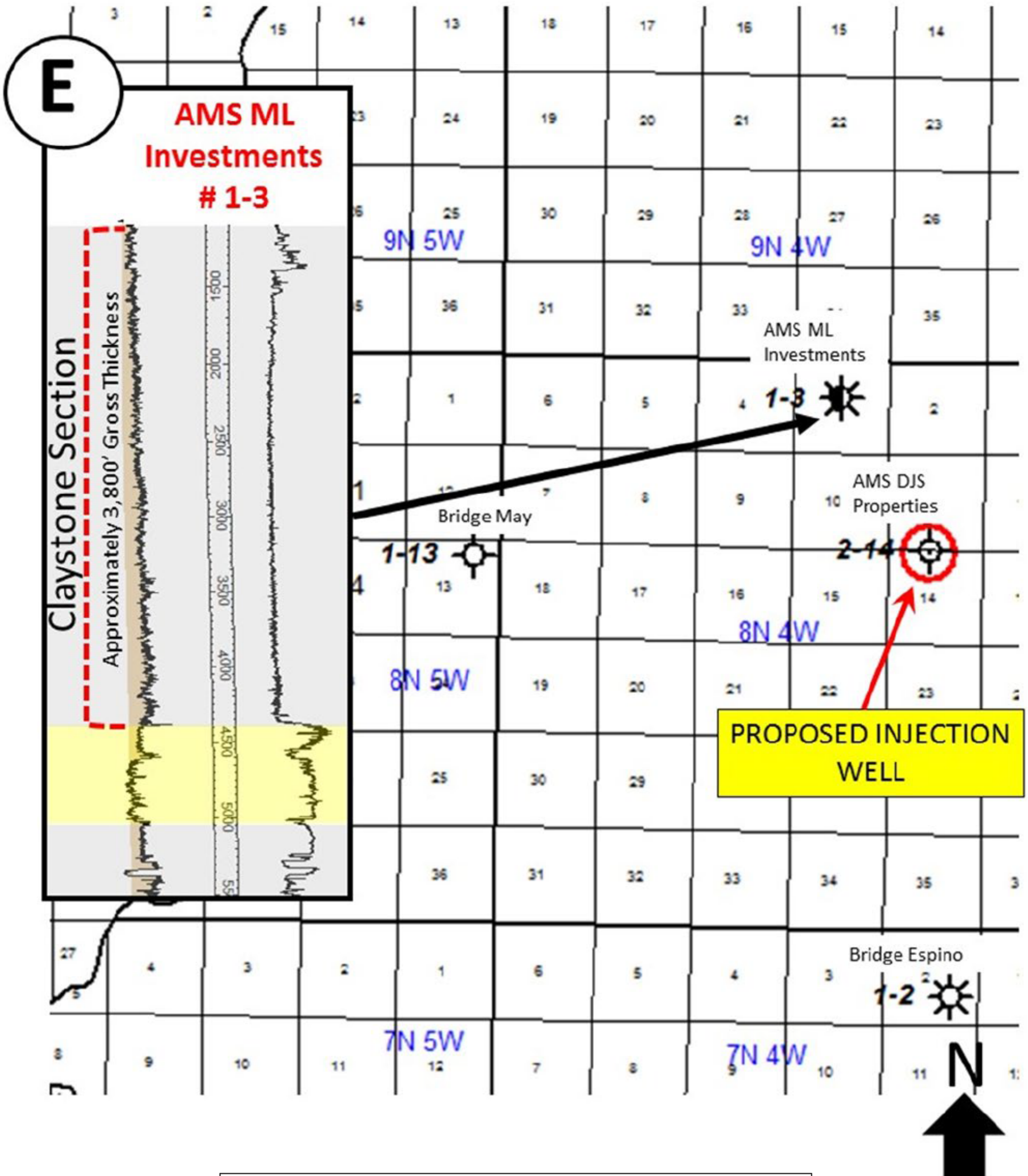
Note: AMS wells operated by Snake River Oil and Gas as of 1-2020

Figure G-8



Note: AMS wells operated by Snake River Oil and Gas as of 1-2020

Figure G- 9



Note: AMS wells operated by Snake River Oil and Gas as of 1-2020

Discussion of Geological and Geophysical Evaluation Methods Used.

Early study of this area included:

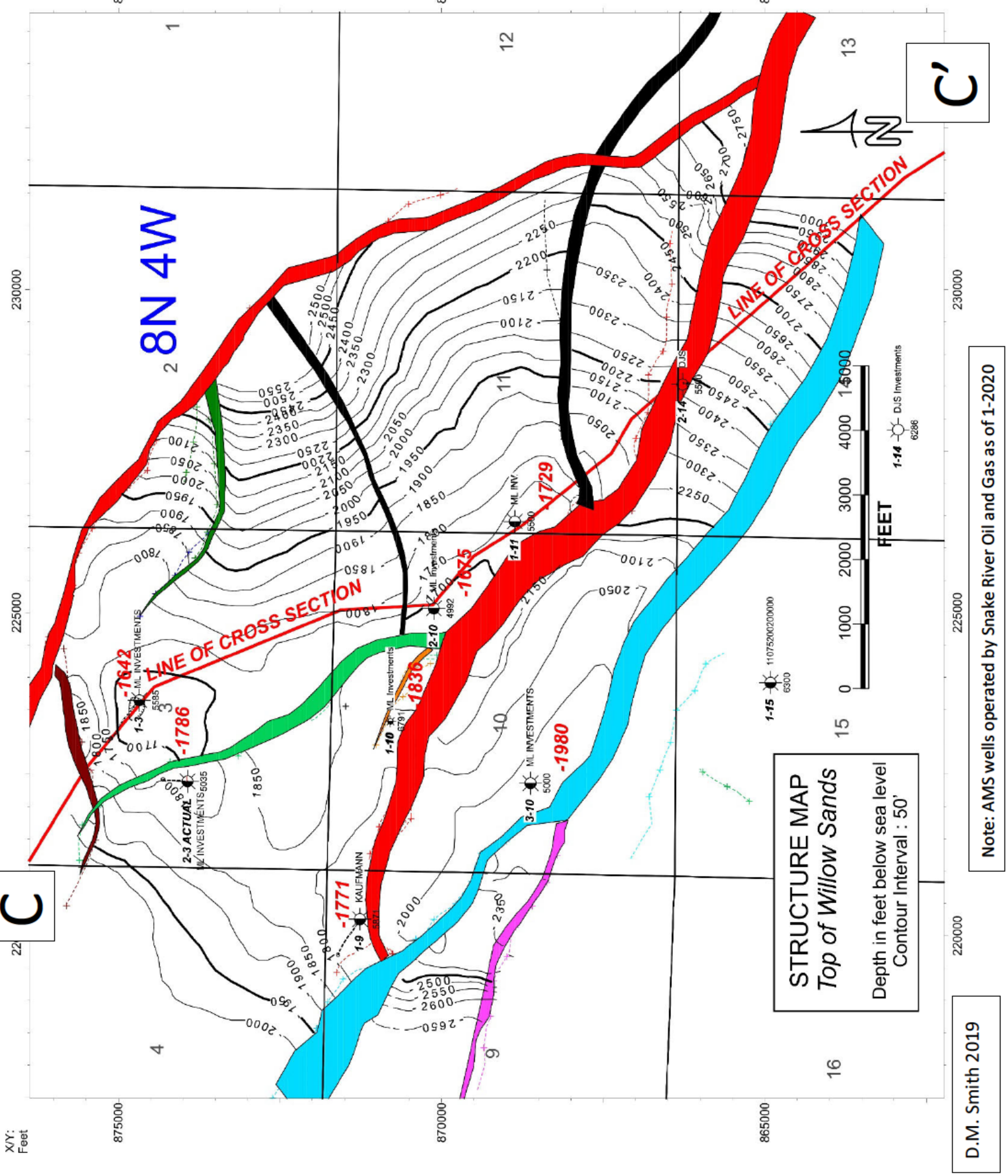
1. Review of a very broad array of prior geologic study in the published literature for regional understanding,
2. Several basin-wide multi-day geologic field trips,
3. Study of prior unsuccessful oil and gas well attempts from 1900 to 2010 – logs, cuttings, etc.

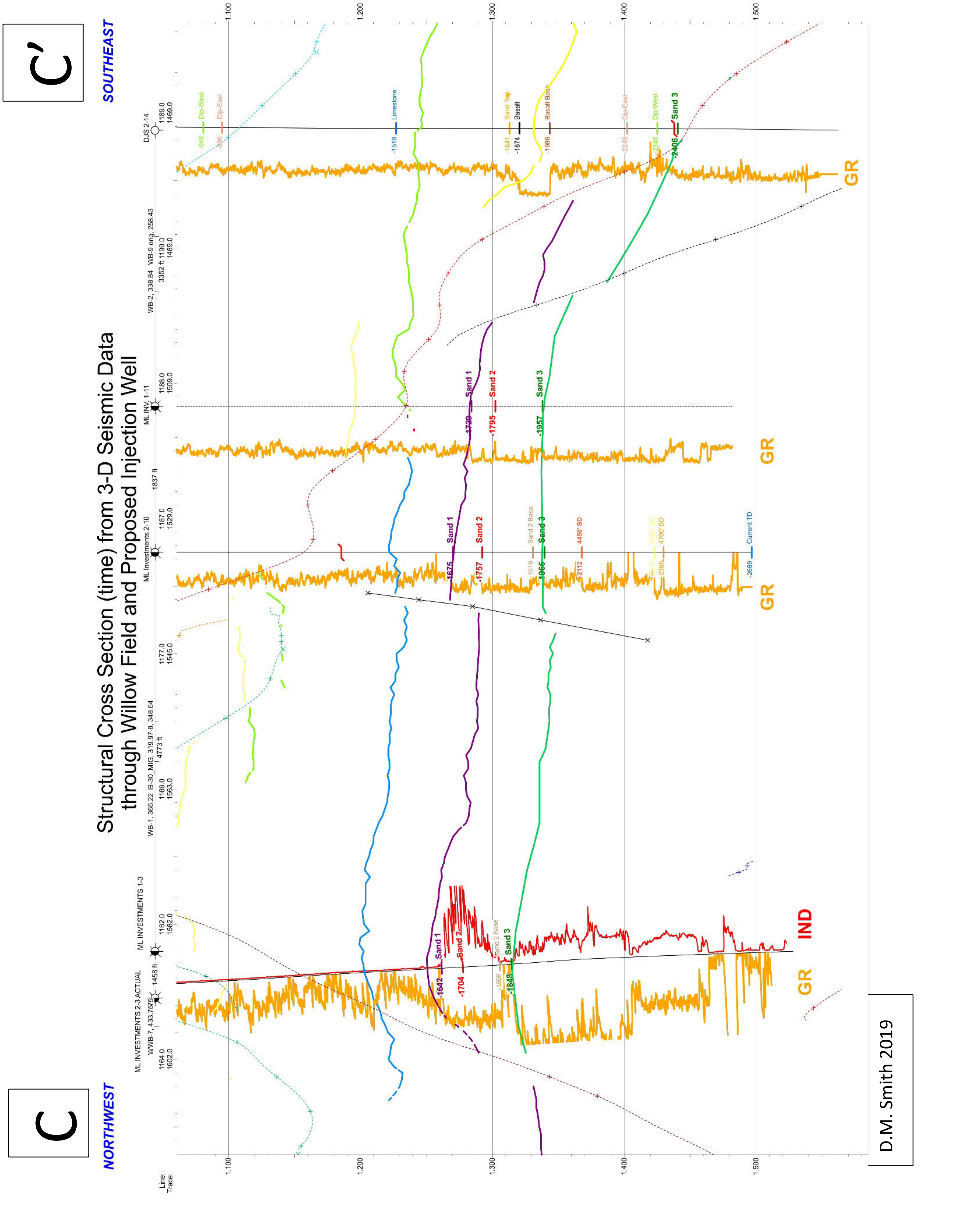
In 2012 we designed and acquired a 49 square mile 3-D seismic survey, centered on this area. The data were processed using refraction statics in Houston, Texas. We interpreted the data and came up with exploration prospects. We drilled the discovery well (ML #2-10) and several successful development wells in what is now Willow Field.

See **Figure G-10** for a structure map at the top of the Willow Sands – which is the oil and gas reservoir for the field. The Field is a 4-way structural closure bisected by small (50' – 250') syndepositional faults.

Figure G-11-A is a NW-SE structural **cross-section C-C'** that runs through 3 wells producing oil and gas from the Willow Sands, and the proposed injection well (DJS 2-14). The log curves shown to the left of each wellbore are the Gamma Ray Logs, and demonstrate the Willow Sands location and thickness. **Figure G-11-B** shows the 3-D seismic data that the interpretation is derived from. The detailed interpretation shown is a result of having high quality seismic data with 82.5' bins.

Figure G- 10


8N 4W
C
C'
LINE OF CROSS SECTION
STRUCTURE MAP
Top of Willow Sands
Depth in feet below sea level
Contour Interval : 50'
Note: AMS wells operated by Snake River Oil and Gas as of 1-2020
FEET
D.M. Smith 2019
X/Y:
Feet


Structural Cross Section (time) from 3-D Seismic Data
through Willow Field and Proposed Injection Well
NORTHWEST
SOUTHEAST
C
C’
GR
IND
D.M. Smith 2019

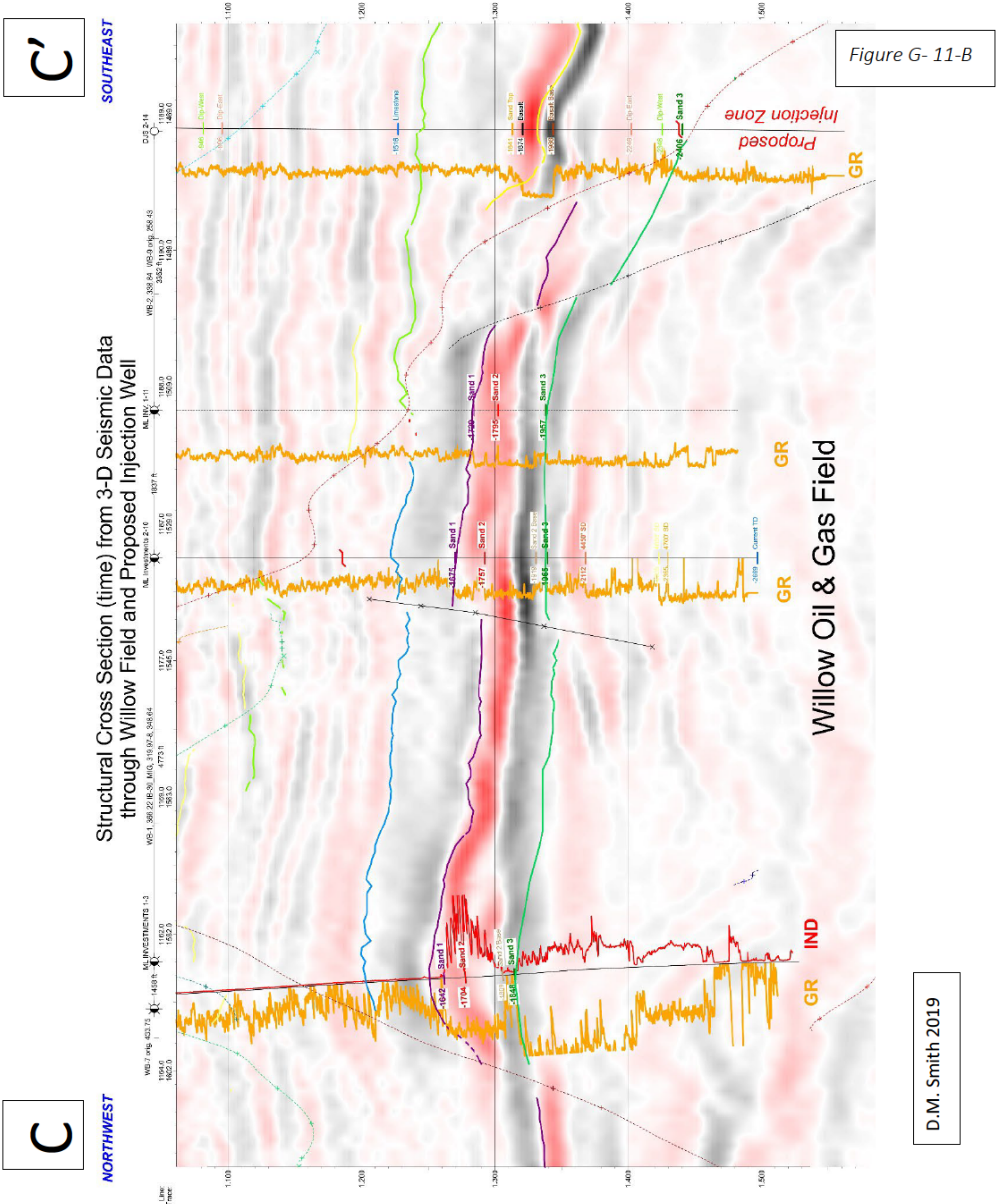

C'
SOUTHEAST
C
NORTHWEST
Structural Cross Section (time) from 3-D Seismic Data
through Willow Field and Proposed Injection Well
Willow Oil & Gas Field
Proposed
Injection Zone
GR
IND
Sand 1
Sand 2
Sand 3
D.M. Smith 2019

Figure G- 11-B

Summary Evidence for Sealing Nature of the Faults.

1. As discussed previously, the overlying clays and ash beds documented in all of the area wells provide an excellent confining layer.
2. Each productive fault block is essentially an upthrown 3-way structural trap against a fault. For oil and gas to be trapped here in large commercial accumulations, the faults must by definition be sealing, and not open to shallower zones. The plastic, malleable character of the overlying *and adjacent* Chalk Hills clays and ash beds is here proven to be a viable and competent seal.
3. The small faults present in the area are syndepositional (movement in a dip direction coincident with deposition of the sediment). They typically have small dip offset (50' – 200') and none have lateral displacement. This character means the movement was early, and likely has ceased. The faults are also relatively short in length (typically a few thousand feet or less), also suggesting only early dip displacement.
4. <u>Comparing pressure behavior in Fault block A vs Fault block B (**Figures G- 12 and G-13**)</u>:
    - Pressure behavior between fault block A and fault block B suggest that the two fault blocks are isolated from each other and are not in communication (see G-11, Pressure vs Time plot)
    - ML 1-11 and ML 2-10 both are in fault block B and were brought on line in the same month (Aug 2015).
    - The ML 3-10 is situated in Fault Block A, adjacent to Fault Block B. The ML 2-10 and ML 1-11 were on production for approx. 28 months before the ML 3-10 was opened to production.
    - Note that the ML 3-10 Initial SITP was 1600 psig prior to opening well to production which indicates the reservoir was under virgin pressure conditions. Virgin reservoir pressure gradients run approx. 0.43 psi / ft
    - If these two fault blocks were in communication, the ML 3-10 well would have been partially pressure depleted and a much lower initial SITP would've been observed.

Comparing Fault block A vs Fault block B –

Figure G- 12

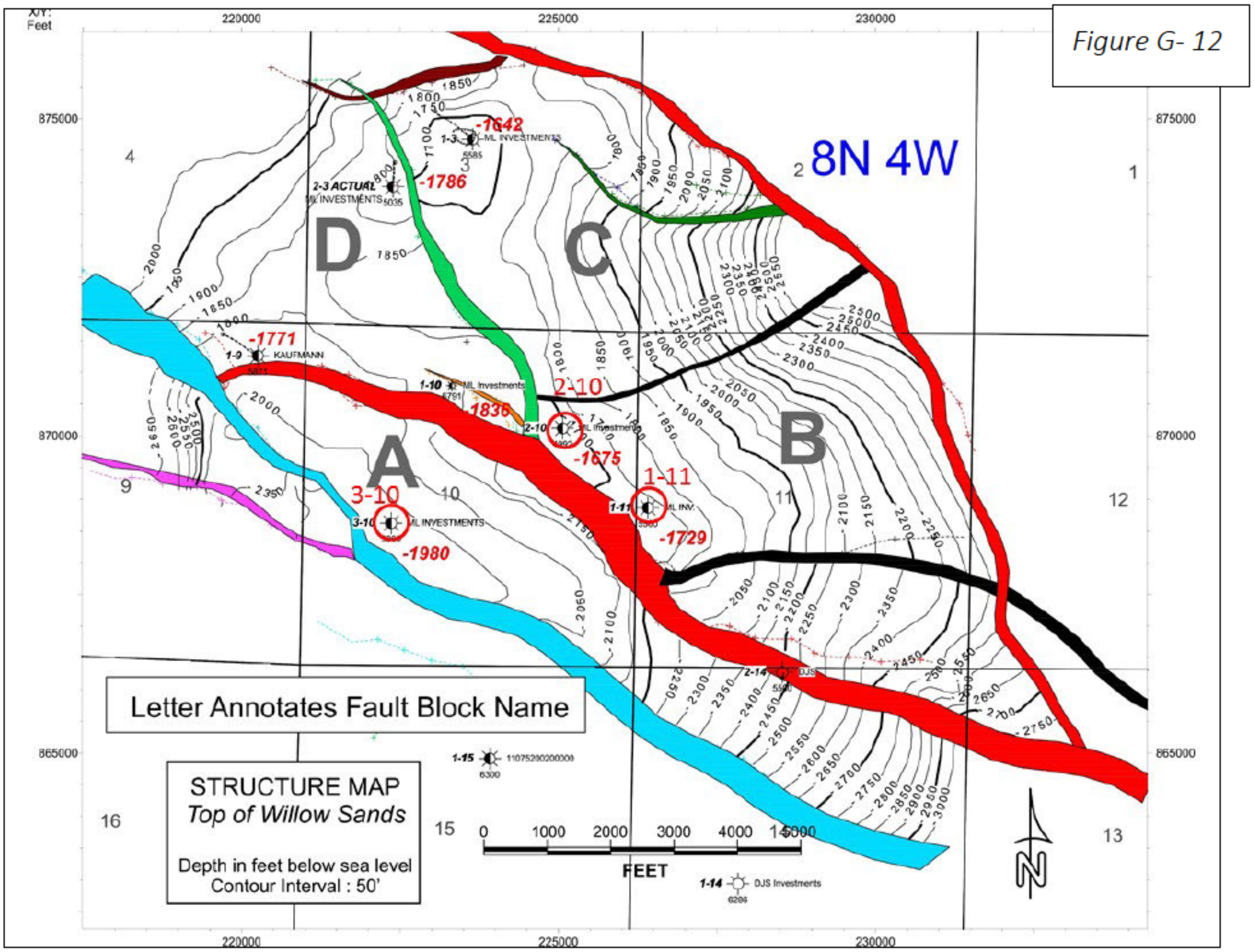
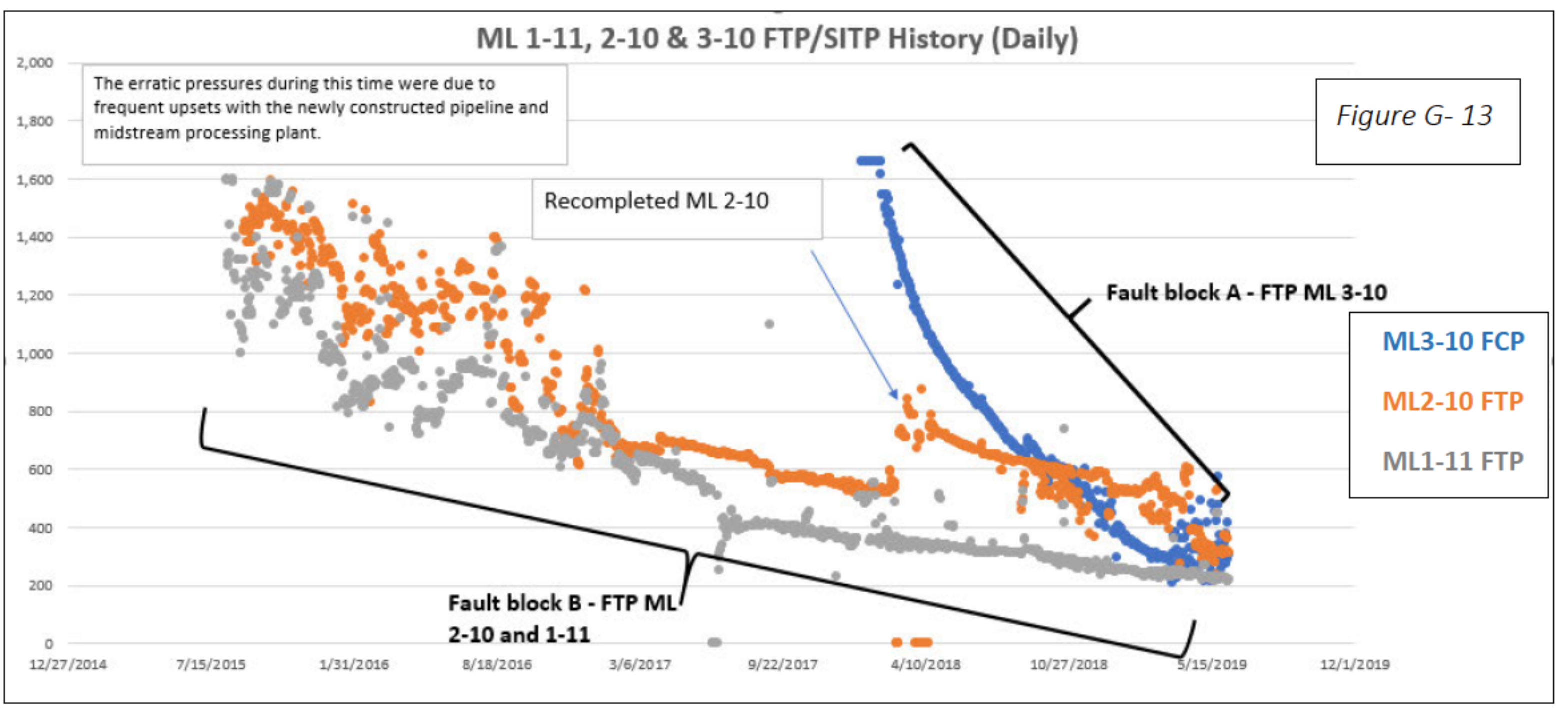


Figure G- 13



Snake River Oil and Gas DJS #2-14 Proposed Disposal Well Geologic Setting

Township: 8 North - Range: 4 West - Section 14
Payette County , Idaho

The following structure and Isopach maps were created from interpreting proprietary 3-D seismic data in conjunction with subsurface well control. Subsurface to seismic ties were done by making synthetic seismograms and verifying ties with seismic modelling. Due to the subsurface presence of basalts (very high acoustic impedance), the seismic to subsurface ties are excellent. The quality of the seismic data is very good to excellent, lending strong confidence to the interpretations Presented herein.

Figure G- 14

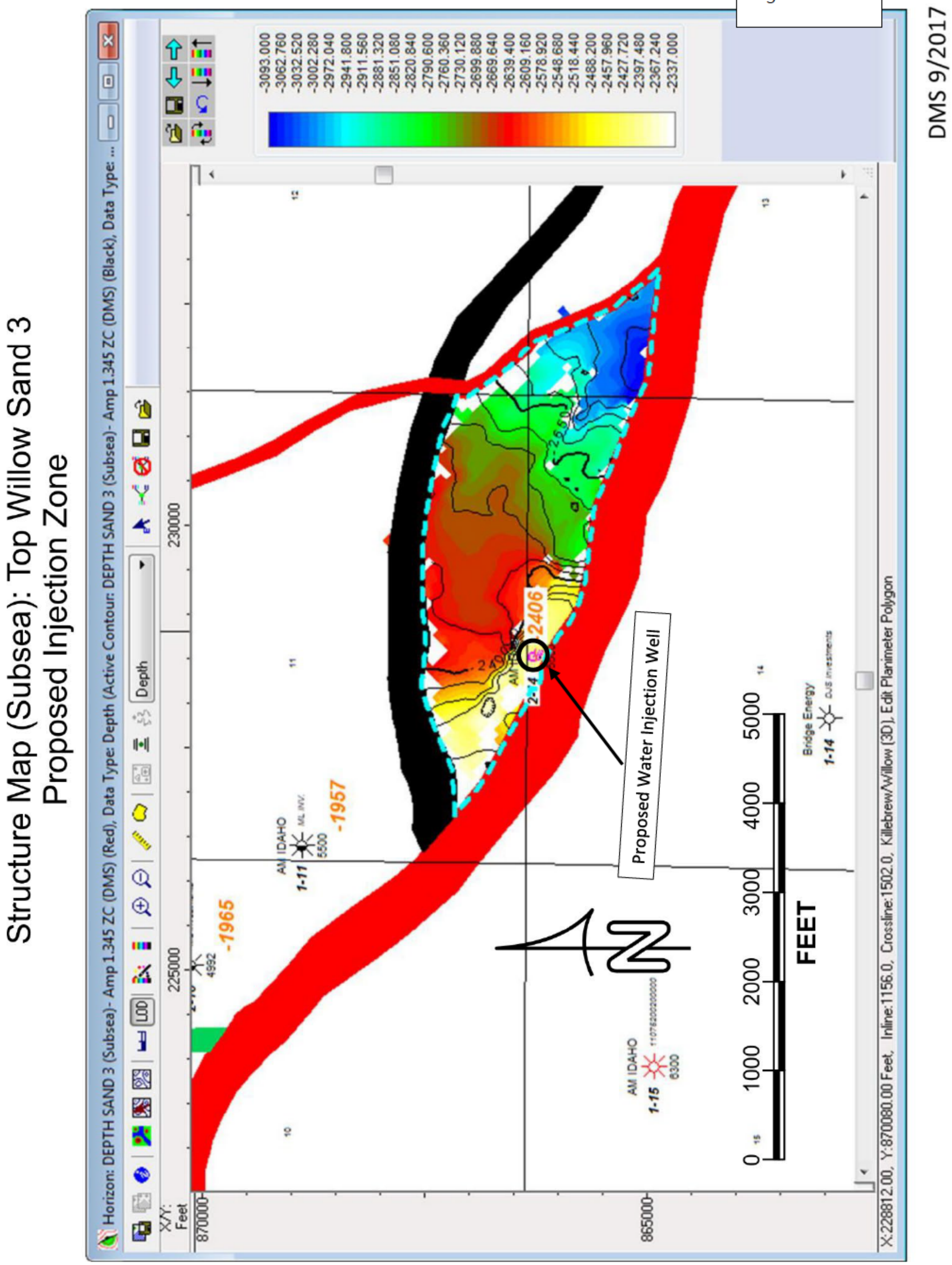
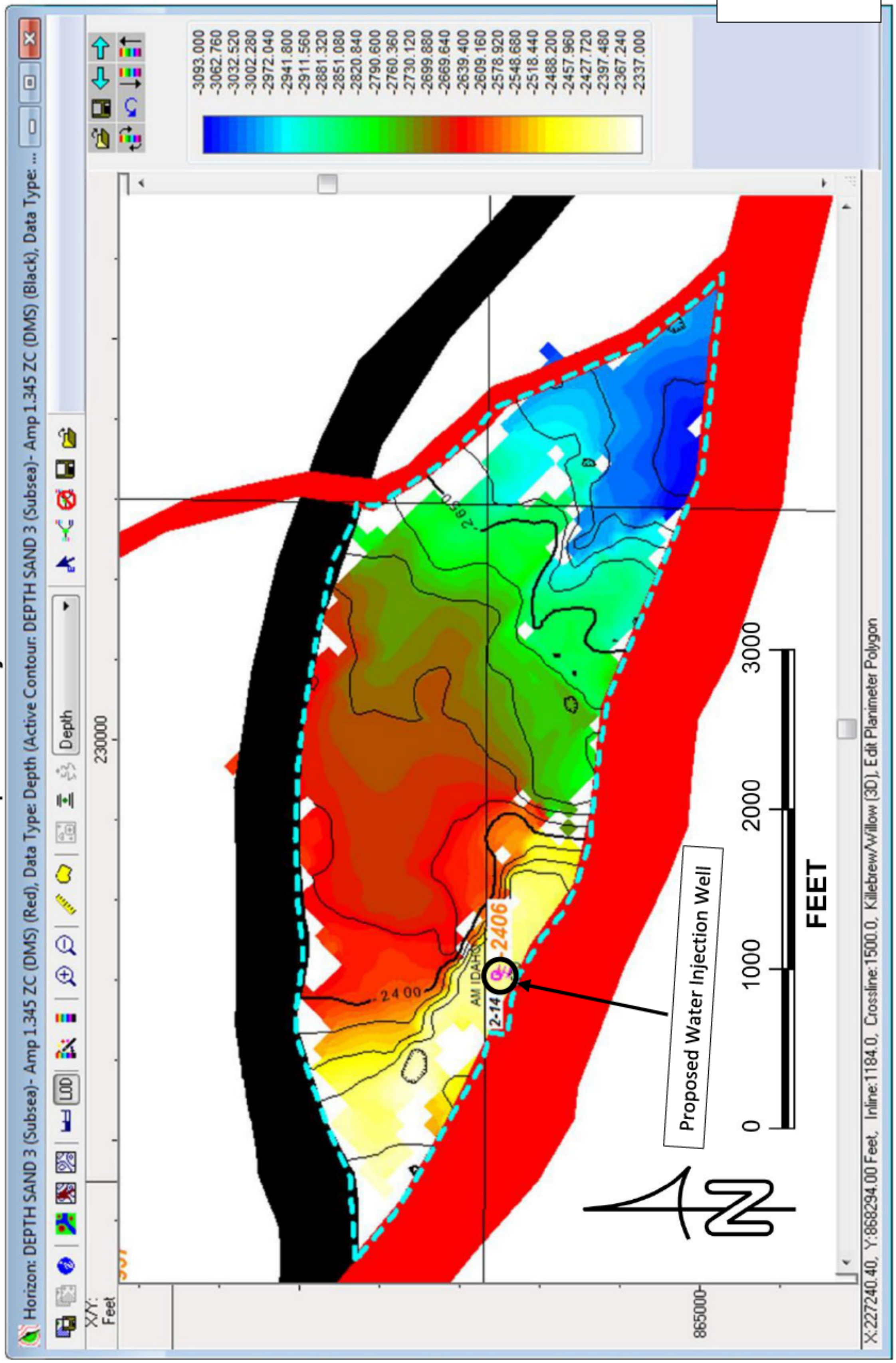

Structure Map (Subsea): Top Willow Sand 3
Proposed Injection Zone
DMS 9/2017
Proposed Water Injection Well
FEET
0
1000
2000
3000
4000
5000
-1965
-1957
2406
AM IDAHO
1-11
AM IDAHO
1-15
Bridge Energy
1-14
225000
230000
870000
865000
X:228812.00, Y:870080.00 Feet, Inline:1156.0, Crossline:1502.0, Killebrew/Willow (3D), Edit Planimeter Polygon

Figure G- 15

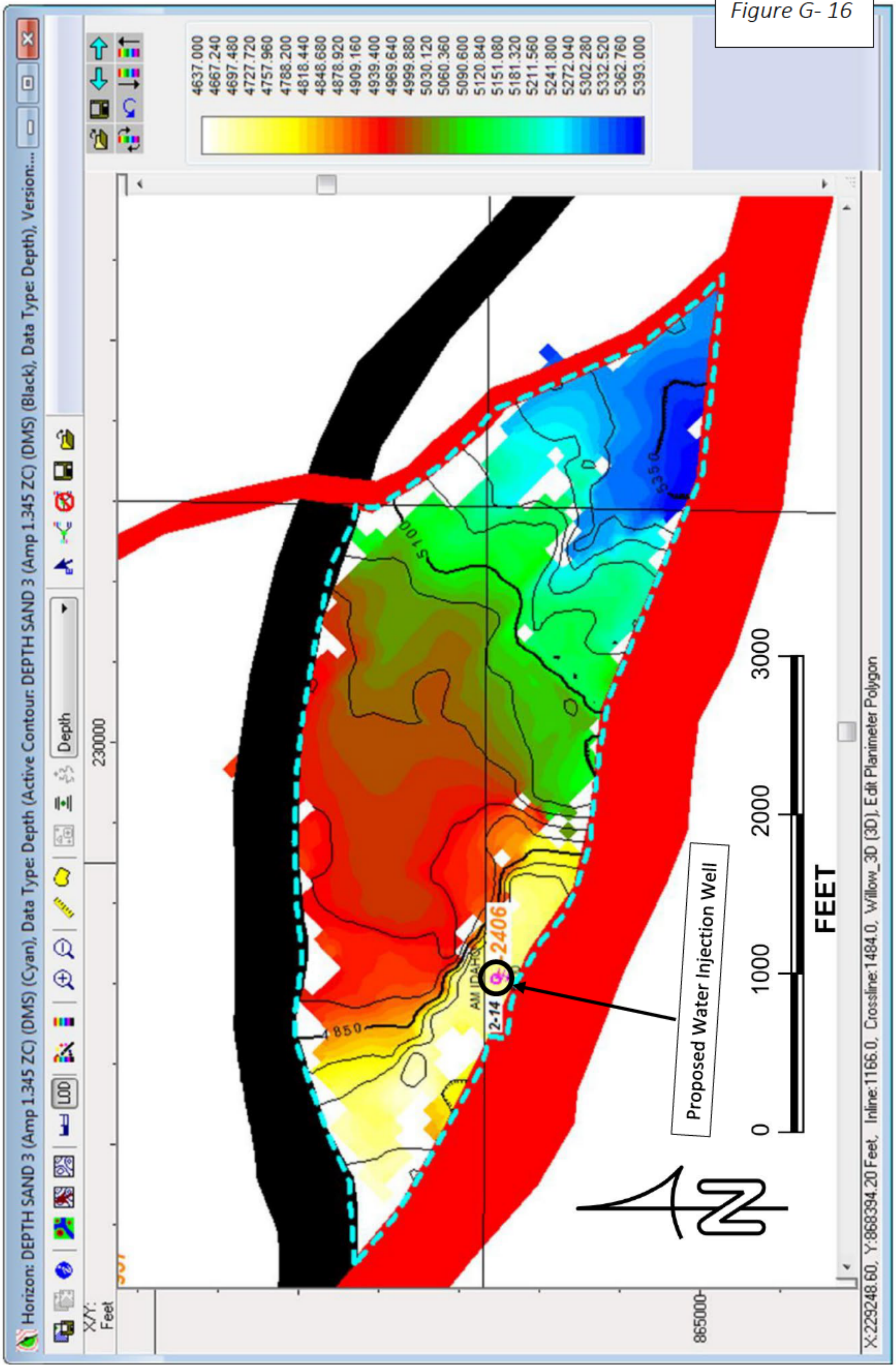
Structure Map (Subsea): Top Willow Sand 3
Proposed Injection Zone



DMS 9/2017

Structure Map (Below Ground Level Datum of 2300' ASL):
Top Willow Sand 3 - Proposed Injection Zone

Figure G- 16



DMS 9/2017

Figure G- 17

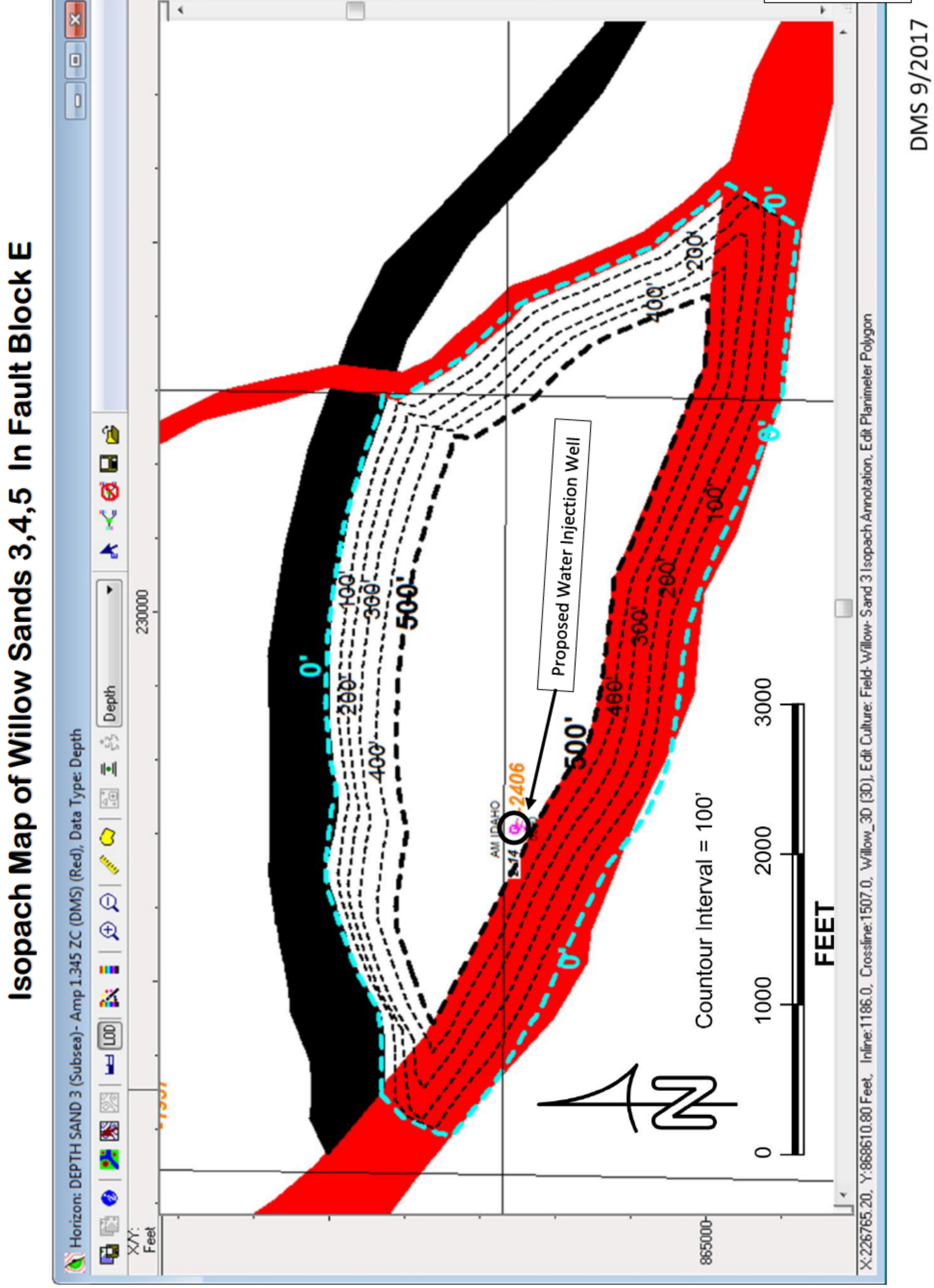
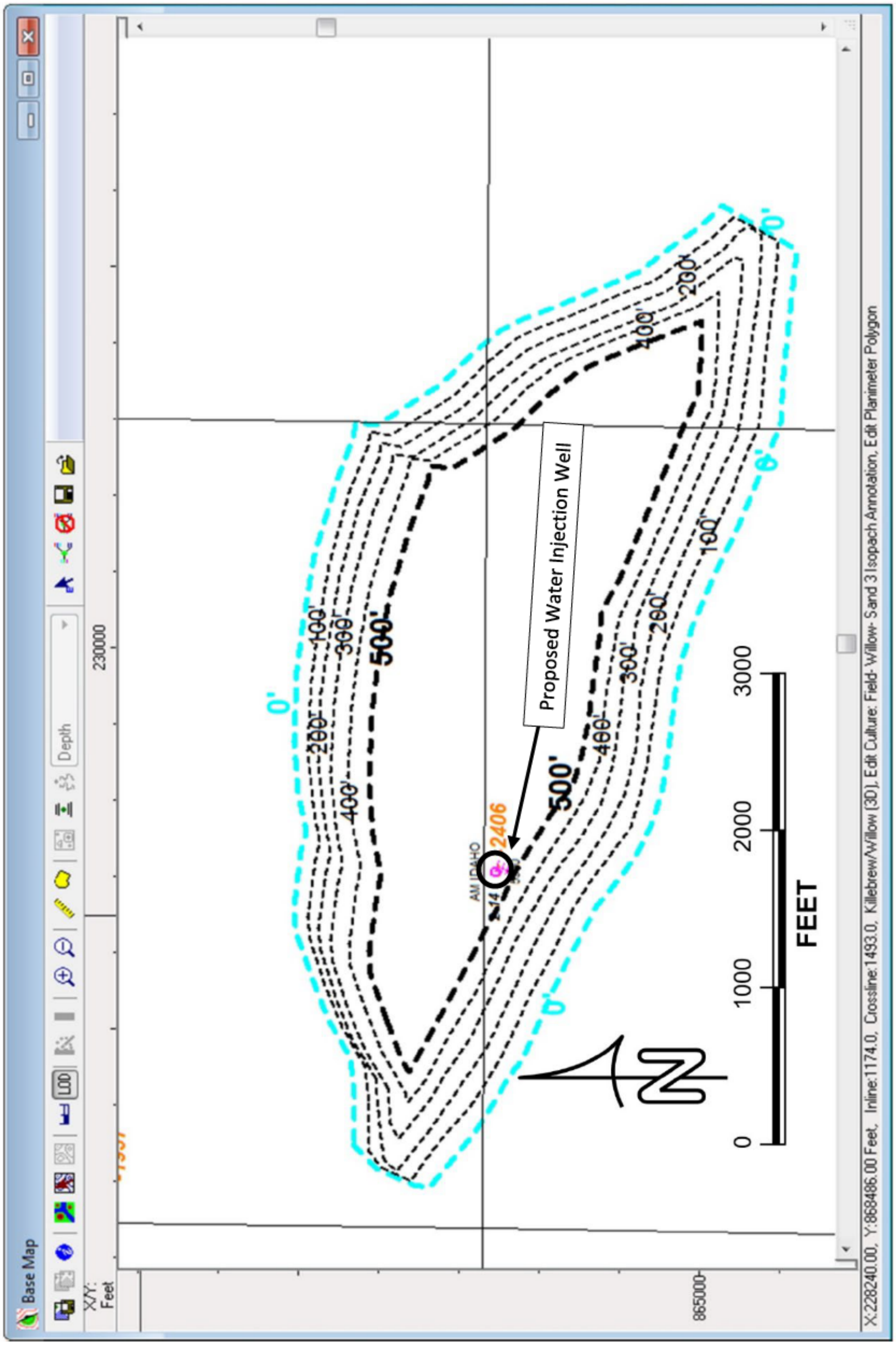

Isopach Map of Willow Sands 3,4,5 In Fault Block E
Horizon: DEPTH SAND 3 (Subsea)- Amp 1.345 ZC (DMS) (Red), Data Type: Depth
Depth
X/Y: Feet
230000
865000
0'
100'
200'
300'
400'
500'
AM IDAHO
2406
Proposed Water Injection Well
Contour Interval = 100'
0
1000
2000
3000
FEET
X:226765.20, Y:868610.80 Feet, Inline:1186.0, Crossline:1507.0, Willow_3D (3D), Edit Culture: Field- Willow- Sand 3 Isopach Annotation, Edit Planimeter Polygon
DMS 9/2017

Figure G- 18

Isopach Map of Willow Sands 3,4,5



DMS 9/2017

Fracture Pressure Estimate of the Confining Intervals

Claystone / Shale – Calculate Frac Pressure in Lower Chalk Hills formation (shale). This is nearest to the top of the injection zone at 4910'.

General Equation using Hubbard & Willis correlation which takes into account overburden gradient (Sz) and Poisson's Ratio (u) component.

FG = u/1-u(Sz – PG) + PG

Poisson's Ratio (u) = 0.40 psi   Note: this is a general rule of thumb for 100% shale formations with 0% porosity and zero permeability. Typical range for "u" for shales are values between 0.35 – 0.45. For this calculation, I have chosen the midpoint – 0.40.

Typical Overburden stress values for 100% shales are 1.23 psi / ft.

Generally speaking, the frac pressure can be calculated within the confining intervals by using the calculated Frac Gradient (FG).   Using the equation above, the FG = 0.96

Using the base of the 1st confining interval at 4910' the frac pressure can be calculated as follows: 0.96*4910' = 4732 psi. Again, this is assuming 100% claystone / shale with zero perm and zero porosity.

ATTACHMENT H: Operating Data

H. Operating Data – The expected average daily rate and volume is 1000 barrels per day (BPD) / 1000 barrels (BBL). The maximum daily rate and volume is expected to be 2600 BWPD / 2600 BBL, based on a mechanistic hydraulic model of the wellbore tubulars and the reservoir characteristics.

The average and maximum surface injection pressures are estimated to be 199 (psig) and 628 psig, respectively, based on the hydraulic model.

The fracture pressure in the lower Chalk Hills Formation @5390' has been estimated at 3214 psi, based on a 12 ppg equivalent fluid density. A leak off test will be run during the completion procedure to verify the fracture pressure of the confining zone as necessary. Dipole sonic data may become available prior to the completion construction procedure, and will be utilized instead of performing a leak off test to provide the capability to calculate Poisson's ratio and the associate frac gradients in the injection and confining zones. In addition, a step-rate test will be run prior to injection operations to determine actual fracture pressure in the injection zone. Injection operations will be controlled to always provide at least 50 psi below that pressure.

The tubing / casing annulus will be filled with 8.8 lb/gallon potassium chloride water, supplemented with an appropriate corrosion inhibitor, biocide, and oxygen scavenger chemical additive package. (See appendix H for the MSDS's).

A step-rate test will be performed after initial commissioning of the injection facilities and well. The step rate test will allow the reservoir parting pressure to be determined and subsequent injection rates will be limited to maintain injection pressures at least 50 psi below this pressure.

The source of the injection fluid is produced water, associated with the oil and gas production operations of wells operated by Snake River Oil and Gas LLC in the surrounding area. An analysis of the produced water is attached (see appendix S for full analyses). The produced water in this area is very low salinity and low TDS since the geologic sedimentary history is that of a lacustrine nature.

H- Reservoir and Petrophysical Information:

A calculation of the expected injection reservoir capacity was performed. This calculation assumes a confined reservoir pore space as defined by the isopach of the injection zone in a fault block bounded on 3 sides by faults (see Attachment G for details). The bulk volume is calculated by determining the area of each isopach interval and using the average of the areas to calculate the total bulk injection reservoir volume. A porosity of 23% is estimated from open hole wireline logs for the injection interval. Water saturation is estimated at 80%, with a complementary 20% gas saturation. This is based on the swab test of the 5380' – 5390' perforations, where gas blows were experienced and a water sample showed the presence of Benzene and other VOC's naturally associated with water associated with hydrocarbon reservoirs. The average net reservoir to bulk thickness ratio is estimated at 90% from a review of the mud log for this interval. The pore space is estimated to contain 152 million reservoir barrels. Under confined injection, the water, gas, and pore space will compress and expand respectively to allow for water influx as pore pressure increases. The maximum allowable pressure is defined by staying 10% below fracture pressure. Fracture pressure is estimated to be equivalent to a 12 lb/gallon gradient (3214 psi at 5150'). Note that the actual parting pressure will be well defined upon completion of the well by the execution of a step rate test. The original pressure is estimated at a pressure equal to an 8.6 lb/gallon equivalent pressure gradient (2276 psi at 5150'). The maximum allowable pressure used in the calculation of Injection Zone Capacity is 90% of the fracture pressure (90% of 3214 = 2892 psi). This provides for an allowable increase in the reservoir pressure of 616 psi (2892-2276). Water, gas, and pore space compressibility's are estimated using standard oil and gas industry correlations. Based on the original reservoir volume, along with the allowable pressure increase and the sum of the compressibilities, it is estimated that a total of 7,773 thousand reservoir barrels can be injected into this space before the pressure limit is reached. This equates to 7,368 thousand stock tank barrels based on a water reservoir volume factor of 1.055 RB/STB. Stock tank barrels are measured at atmospheric pressure and 60 degrees F. See Figure H-1 for volumetric calculations.

H-1 Calculation of Confined Injection Zone Capacity

Calculation of Confined Injection Zone Capacity

DJS Properties #2-14 Injection Zone

Calculation of Reservoir Volumes:

Porosity	0.23	fraction	from well log
Sw	0.80	fraction	water saturation - evidence of gas in swab testing and water analysis
Sg	0.20	fraction	gas saturation - evidence of gas in zone from swab testing - residual gas
Gross Volume	94,700	acre-ft	from planimetry calculations below
Net/Gross Ratio	0.90	fraction	from well logs
Pore Volume	19,603	acre-ft	

Reservoir Isopach Area Planimeter Readings:

CONTOUR LINE VALUE	AREA > (acres)	RATIO OF AREAS	DELTA CONTOUR (ft)	DELTA VOLUME (acre-ft)	
0	269.00				
100	234.00	0.8699	100	25,150.0	
200	205.00	0.8761	100	21,950.0	
300	173.00	0.8439	100	18,900.0	
400	144.00	0.8324	100	15,850.0	
500	113.00	0.7847	100	12,850.0	
		TOTAL ==>		94,700.0	acre-ft - gross bulk reservoir volume

Injection Zone Capacity

Item	Value	Units	Comments - notes
Datum Depth:	5150	ft, BGL	average depth of injection zone
Average Temperature	251	deg F	ML Investments 1-3 production log
Initial Pressure:	2276	psi	8.6 ppg equivalent pore pressure at datum depth
Fracture Pressure:	3214	psi	12 ppg equivalent pore pressure at datum depth
Maximum Allowable Pressure	2892	psi	90% of fracture pressure
Maximum Pressure Increase (dP)	616	psi	maximum allowable pressure less initial pressure
Average Pressure	2584	psi	average of initial pressure and maximum allowable pressure
Water Salinity	750	ppm Cl	estimated average
Water Compressibility	3.48E-06	1/psi	Osif's Correlation
Gas Compressibility	3.87E-04	1/psi	Meehan et al, Gas gravity = 0.65 from ML Investments 1-10 Well
Rock pore volume compressibility	3.50E-06	1/PSI	Hall's Correlation
Reservoir Water Volume Initial	15,682	acre-ft	Pore Volume * Sw
Reservoir Water Volume Initial	121,663,439	RBbls	Pore Volume * Sw
Reservoir Water Volume Compression	261,022	RBbls	dP * water compressibility* initial water volume
Reservoir Gas Space Volume Initial	3,921	acre-ft	Pore Volume * Sg
Reservoir Gas Space Volume Initial	30,415,860	RBbls	Pore Volume * Sg
Gas Pore Space Compression	7,250,191	RBbls	dP * gas compressibility * initial gas volume
Pore Space Volume Increase	262,281	Rbbls	dP * pore space compressibility
Total Pore Space volume increase	7,773,494	RBbls	sum of water, gas, and pore space compression
Bw (water formation volume factor):	1.055	RBbl/STBbl	McCain's Correlation
Total Stock Tank Barrels Capacity	**7,368,241**	**STBbls**	adjust to surface conditions by dividing by water formation volume factor (Bw)

ATTACHMENT I: Formation Testing Program

I. **FORMATION TESTING PROGRAM –** A step rate test will be run at the time of initial completion to determine the actual parting pressure of the injection interval after the packers and tubing is installed. The water used in this test will be from the same source as the proposed source water. Surface injection pressure and injection rates will be measured during the step rate test. The determination of bottom hole parting pressure will be indicated by a departure in the injectivity ratio (dRate/dPressure) when the parting pressure is exceeded. The pressure defined by the intersection of the slopes of the injectivity data below and above parting pressure will define the surface maximum injection pressure. All injection operations will be held to 50 psi or more below this pressure to assure that fracturing of the injection interval does not occur. Bottom hole pressures will be calculated based on the density of the fluid being injected, along with surface pressure measurements.

Determining Formation Parting Pressure (FPP) using Step Rate Testing (elaboration)

- In general, in order to determine the actual FPP for the proposed injection well, an injection test or step rate test would need to be performed.
- General Procedure
  - Load hole with injection fluids and let well equalize with native formation pressure
  - Begin injection into formation at a constant rate and gradually increase the injection rate in 30 – 60 min time intervals. Suggested rates would range between 0.5 – 5 BPM with 30 – 60 min intervals for each rate in a step rate fashion.
  - Record all pressures and rates during the step rate test.
  - Plot pressure vs rate graphically and identify slope change in pressure (intersection) to determine (FPP). NOTE: Adjust BHP's, accounting for frictional loss due to injection rates down tubular.
  - The FPP is the pressure in which the injection rate shifts from matrix flow to frac dominated flow.
- Determining the FPP for the proposed injection well will dictate the actual surface injection pressure operating range.

Fluid Type – The fluids that will be injected will be the typical field production water (see water analysis of DJS 2-14 and all offset wells/fault blocks in Aquifer Exemption Application).

ATTACHMENT J: Stimulation Program

J. STIMULATION PROGRAM **–** No stimulation program is expected to be needed. The sandstone in this area has good permeability and the unstimulated injectivity should be sufficient.

ATTACHMENT K: Injection Procedures

INJECTION PROCEDURES – Individual monitoring of the DJS Properties #2-14 is planned. Gauges will be installed at the wellsite, and a flow meter will be installed at the pump station. Casing pressure will be maintained at 0 psig. If any pressure is noted on the annulus between the tubing and the production casing, injection will immediately be halted. Injection will not be resumed until the source of the pressure has been identified and repaired. Injection pressure at the wellhead on the tubing will be maintained 50 psi below parting pressure. An initial step-rate test will be performed to determine parting pressure to beginning injection operation. Produced water will be gathered into stock tanks and through additional settling and filtration vessels, as necessary to assure clean water is pumped downhole. A polish filter will be installed at the wellhead to catch any solids that make their way to the wellhead. An injection pump will be located near the stock tanks to pressurize the water and transport the water via flowline to the wellhead. A pressure relief valve will be installed on the pump to prevent excessive pressure from being placed on the flowline. This relief valve will be piped back to the source tanks or to the intake of the pump. Source water will be provided by the producing wells. The flowline will be buried below grade to avoid freezing issues. The portion of the flowline above grade will have insulation and heat tracing to avoid freezing during winter operations. The flowline easement and wellhead will be visually inspected daily (within reason, due to considerations of weather and other force majeure) by field operating personnel.

ATTACHMENT L: Construction Procedures

CONSTRUCTION PROCEDURES –

Historical:

Spud well 9/11/2014. Surface hole was drilled with 12 ¼" bit to 1093'. 9 5/8" 40 lb/ft K-55 LTC casing was then set at 1082' and was cemented back to surface. An 8.75" hole was drilled to 5,500' and production casing was then run and cemented (7" 26 lb/ft J-55 LTC casing with bow spring centralizers). A top down cement job was then performed on the 7" casing, to provide cement coverage between the production casing and the surface casing down below the shoe of the surface casing. The prospective hydrocarbon intervals were then tested by perforating and flow/swab tested each of 5 intervals between 5390' and 4306'. All tested non-commercial. The first zone at 5380-5390' did have good gas blows during swabbing. Cement retainers or bridge plugs were set between intervals during the testing operations which proceeded from the bottom to the top interval, and was also placed above last interval after testing. Testing was completed by 11/3/2014. See attached wellbore diagram.

Planned Well Construction Procedure for Injection:

1. Move in workover rig.
2. Pressure test casing above bridge plug at 4,294'
3. Drill out plugs and retainers to below float collar to 5,450'. If dipole sonic data is not available, run leak-off test prior in the Confining Zone to verify fracture gradient in the Confining Zone.
4. Add perforations in interval 5390 – 5410'.
5. Run tubing, packer and isolation packer to 4860' and set upper packer at 4200'. (see attached wellbore diagram).
6. Install wellhead assembly.
7. Run step rate test with actual produced water to determine parting pressure and injectivity.
8. Connect gauges and filter pod, flowline, pump, and commission injection system.

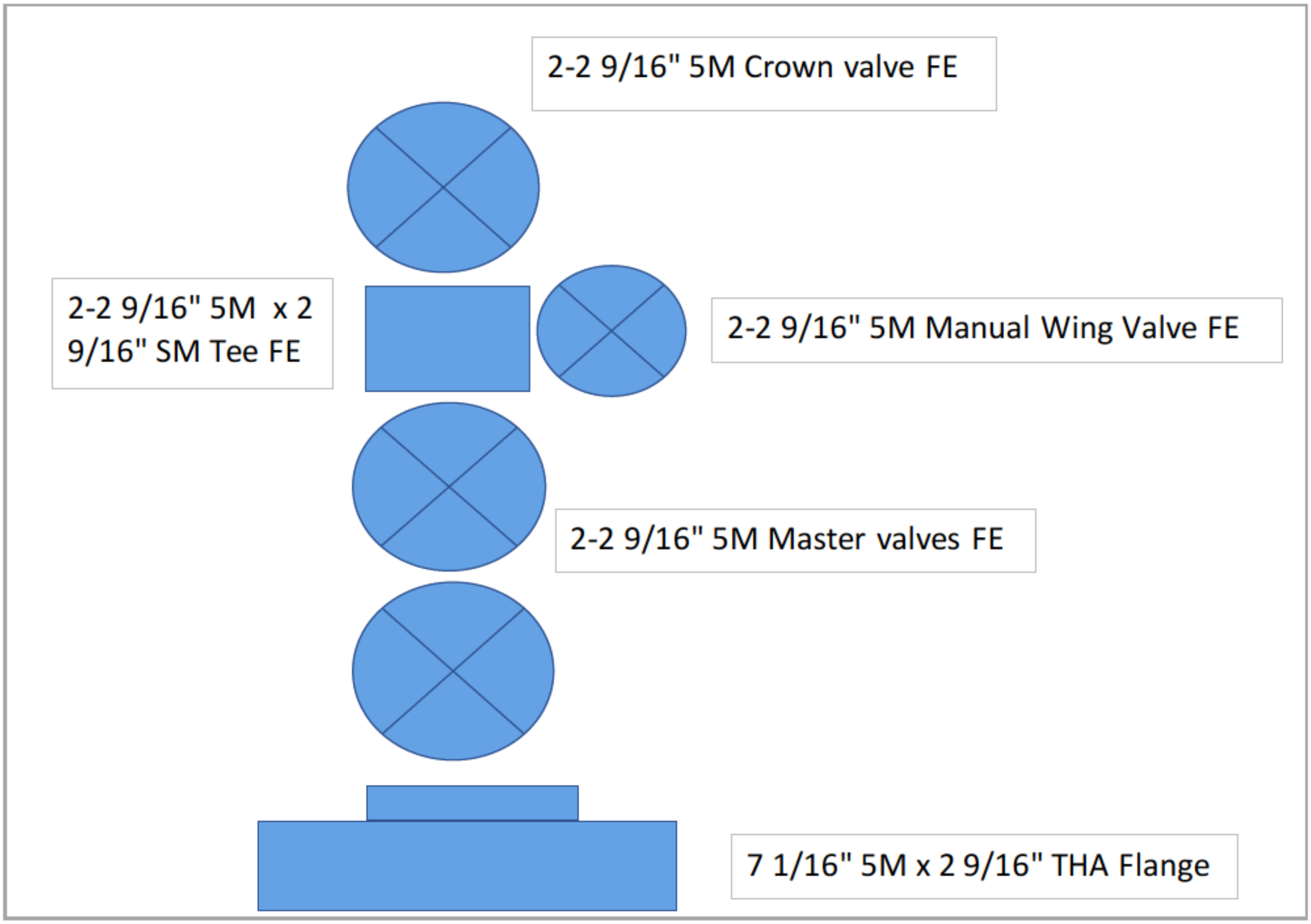
Planned Facilities Construction:

Little Willow Production Facility – Install pump, metering equipment and valving.

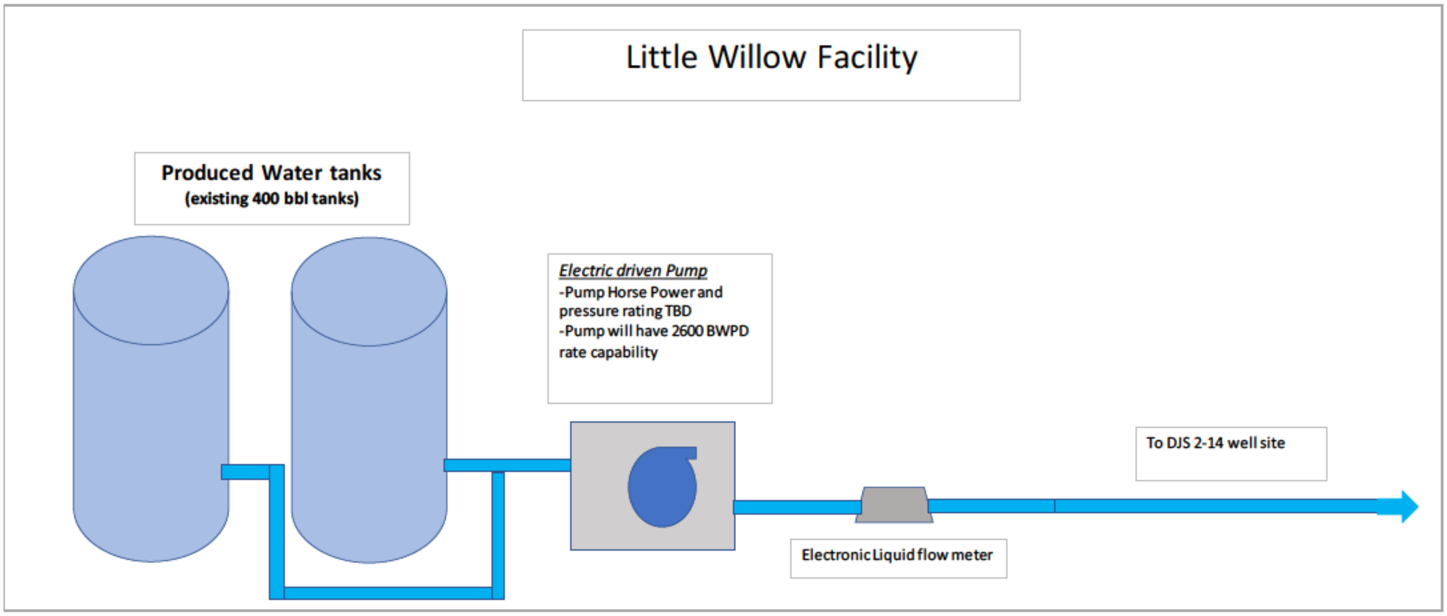
DJS 2-14 well site – Install new wellhead and filter unit.

ATTACHMENT M: Construction Details

M-1 Proposed Wellhead Configuration for the Water Disposal Well

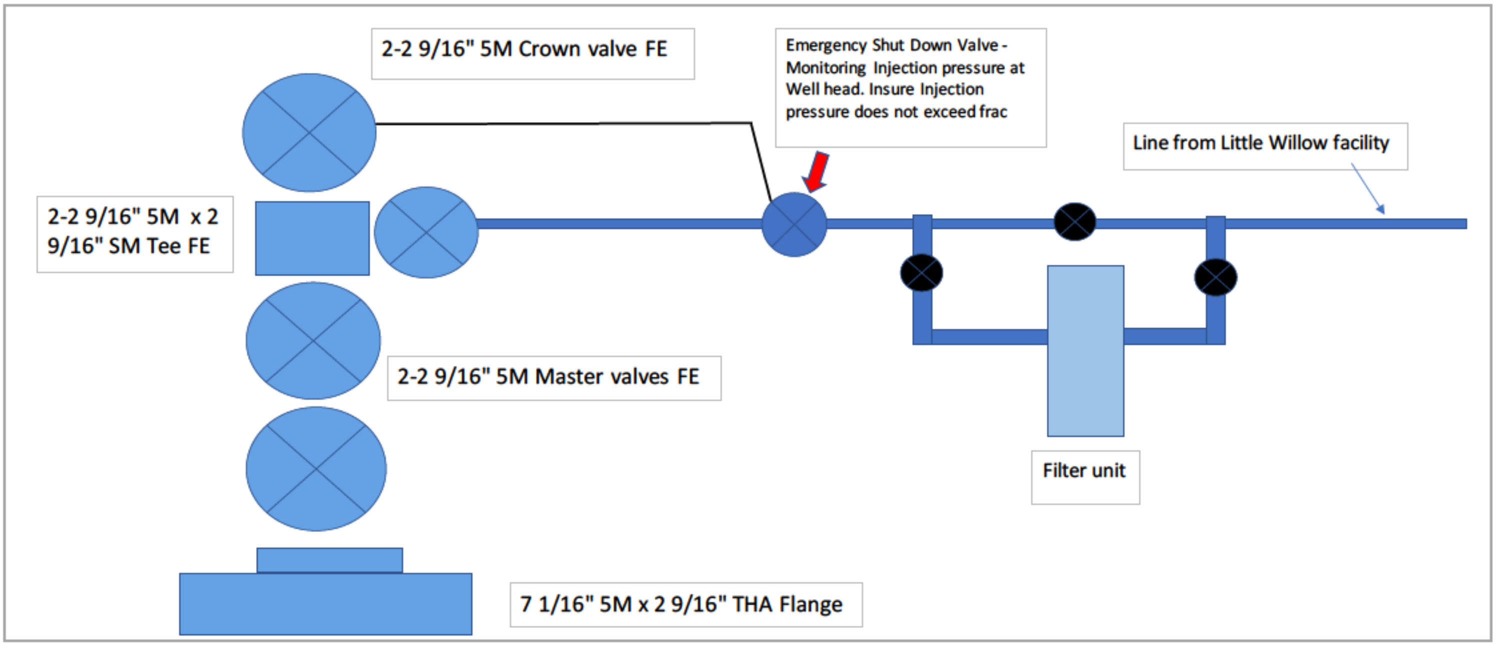


M-2 Proposed Injection Equipment to be installed at Little Willow Production Facility.



- Process Summary – Little Willow Facility: Plan to install an electric driven pump capable of discharging 2600 BWPD (HP and pressure rating – TBD).
- Produced water will be collected into the water stock tanks (current operations) and will feed the suction side of the pump.
- Water will be energized via the pump and then will move through and electronic flow meter before being sent to the DJS 2-14 well site.

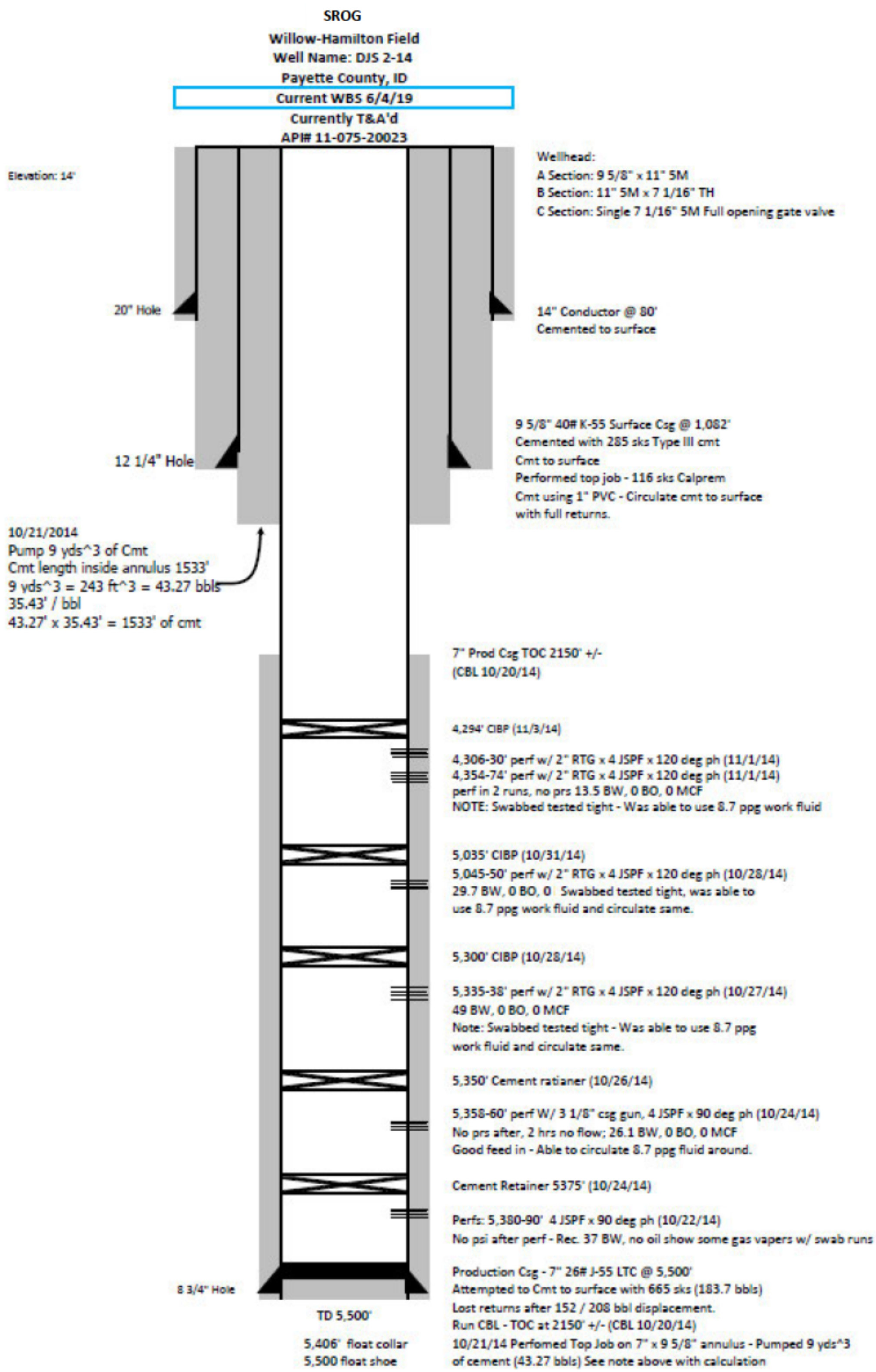
M-3 Proposed Injection Well Site Equipment Layout



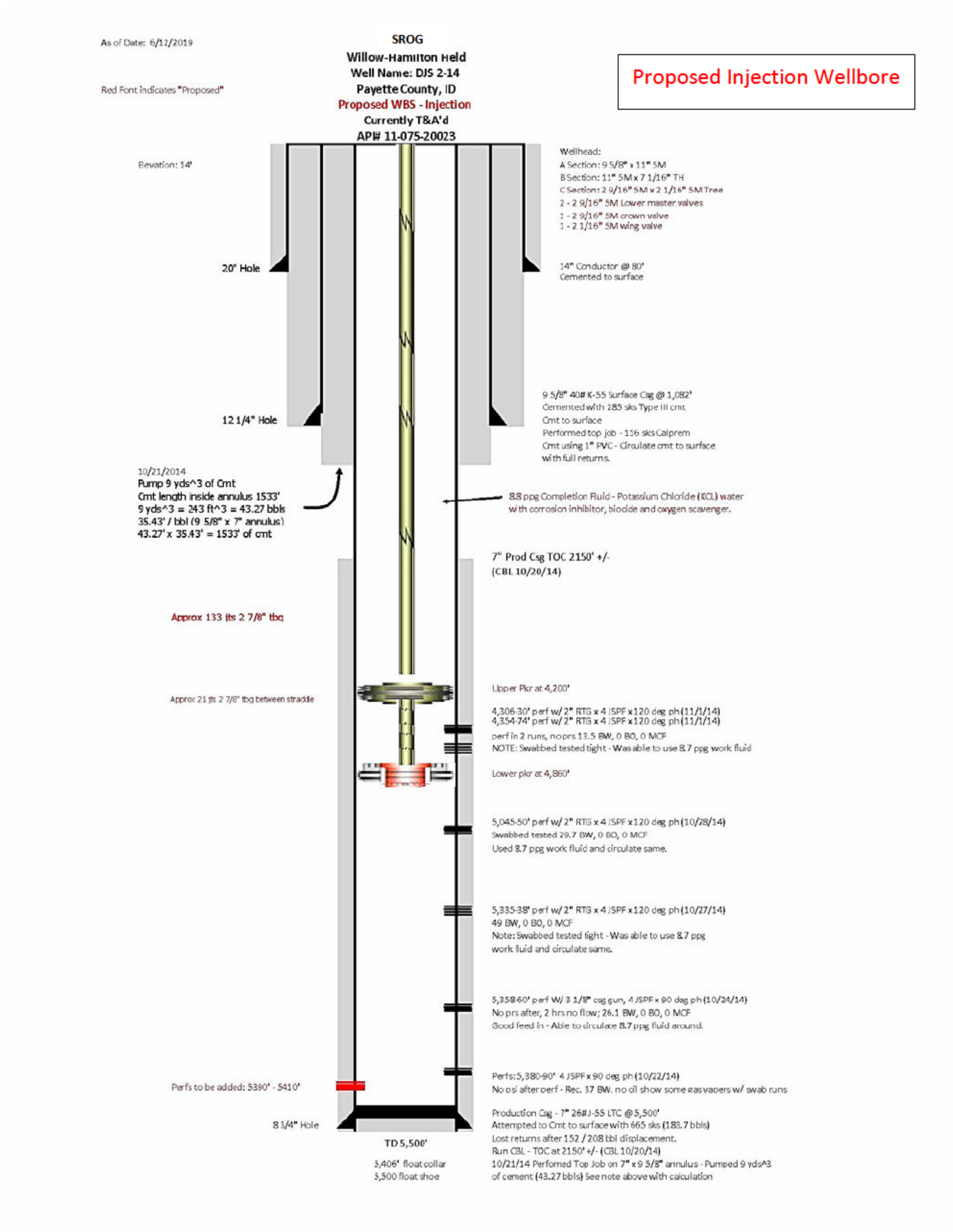
- Process Summary – Water will be transported from the Little Willow Production Facility to the DJS 2-14 well site where it will be filtered before going down hole.
- Additionally, and Emergency Shut Down Valve (ESD) will be installed upstream of the wellhead to ensure that the injection pressure does not exceed the frac pressure during injection service.

CONSTRUCTION DETAILS – See the following pages for wellbore schematics.

Current Wellbore



M-5 Proposed Wellbore Diagram



ATTACHMENT O: Plans for Well Failures

PLANS FOR WELL FAILURES -- The potential areas of concern for this type well are three points: 1) packer to casing seal, 2) tubing connections or tubing body leak, or 3) tubing hanger seals. For any of these components a leak will be indicated by the existence of pressure on the tubing / casing annulus pressure gauge. These type of leaks will be contained within the wellbore envelope. If pressure is observed on the casing gauge, injection operations will immediately cease. The wellhead will be isolated by closing in all wellhead valves and the pump and flowline valves will be closed. The tubing hanger seals will be inspected using a wellhead service company technician who can pressure test the seals for leaks. After this testing is done, a workover rig will be utilized to repair the leaking seals or to pull the tubing and packer so that they can be inspected for leaks and replaced as necessary. Injection will not be reinstated until the leak is repaired and the annulus is pressure tested to verify integrity of the injection components.

Mechanical integrity tests will be run periodically according to permit requirements by applying pressure on the annulus between the production casing and the tubing. This test is designed to detect any production casing weakness. If any leaks are noted, injection operations will not resume until the leak is located and repaired.

ATTACHMENT P: Monitoring Program

A general monitoring program will be implemented for the injection system as well as offset wells in the adjacent fault blocks. This will ensure that all aspects of the injection system are operating within the appropriate ranges as noted in Attachment H.

Monitoring at DJS 2-14 (proposed Injection well) and Pump station (facility).

- Monitor surface pump pressure at facility that is sending water to DJS 2-14 (see Attachment K for detail).
- Monitor tubing Injection Pressure – Should remain within the operating parameters mentioned in Attachment H (199 psi – 628 psi but subject to change with FPP determination).
- Monitor Annulus pressure – Should remain static at 0 psi (see Attachment K for detail).
- Monitor Surface Casing pressure – Should remain static at 0 psi.
- Will inspect and replace gauges at all points of the system as necessary to ensure proper and accurate readings are being recorded.
- Routinely inspect injection flow line route from facility to DJS 2-14 disposal site and confirm there are no line leaks that have developed.
- If there are any abnormalities within the above monitoring criteria, injection operations will cease immediately, and diagnostics will be performed in order to determine the operational issue if it exists.

Monitoring offset wells

- Will continually monitor the offset wells (producing / shut in) for normal operating ranges during injection service. This includes:
    - Monitoring all tubing and annulus pressures as well as all surface casing pressures for each offset well in all associated fault blocks.
- Monitor for normal pressure / temp and rate behavior between wells and report any anomalous pressure / temp or rate changes during injection service.
- Will inspect and replace gauges at all offset wells as necessary to ensure proper and accurate readings are being recorded.
- If there are any abnormalities within the above monitoring criteria, injection operations will cease immediately, and diagnostics will be performed in order to determine the operational issue if it exists.

ATTACHMENT Q: Plugging and Abandonment Plan

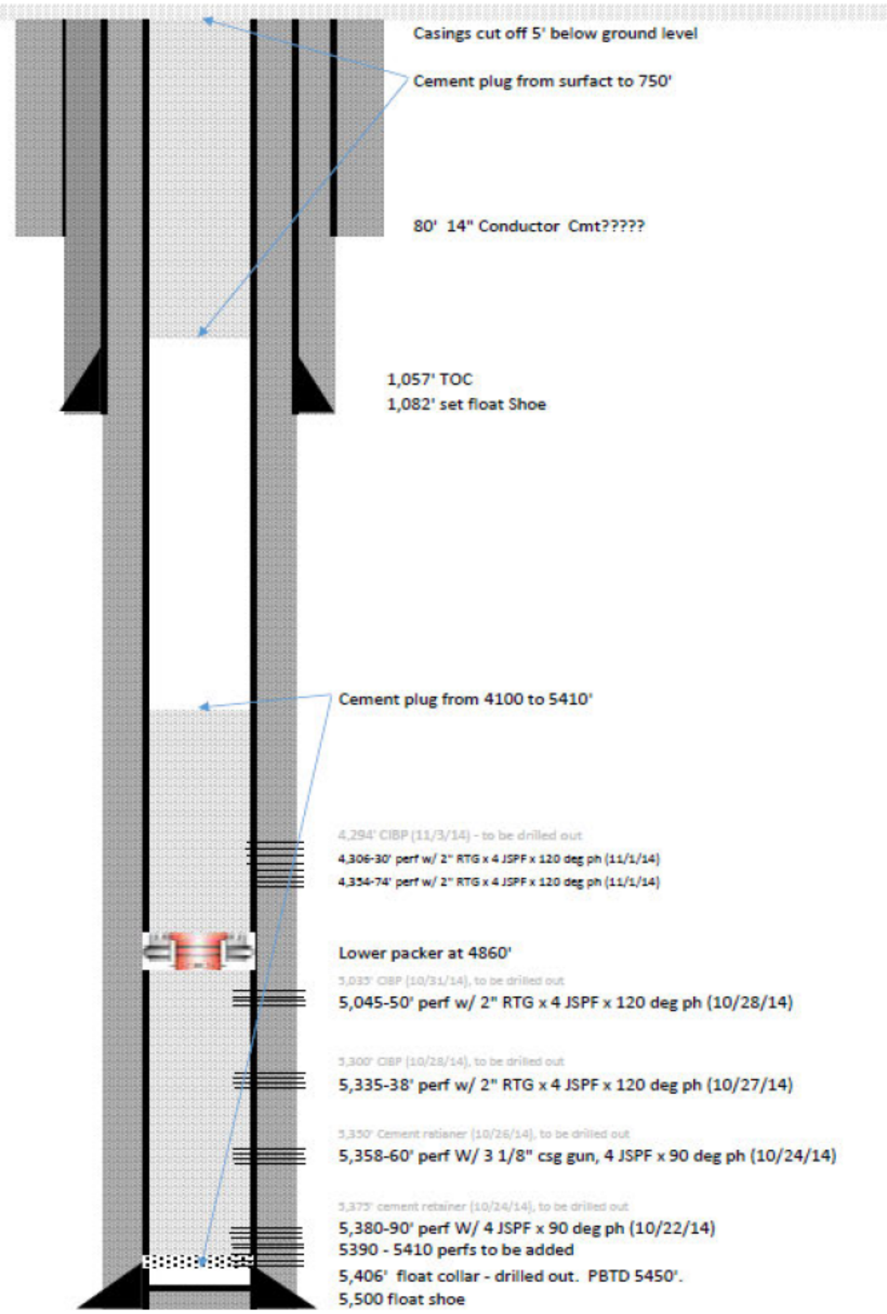
PLUGGING AND ABANDONMENT PLAN – See proposed Post-Injection Plugging Configuration wellbore diagram and associated EPA Form 7520-14 which details the proposed plugging and abandonment plan for this well.

Q-1 Proposed post-injection plug and abandon wellbore diagram

Well name: DJS 2-14
Willow Field - Payett County, ID
Proposed post-injection plugging configuration
Spud 9/12/2014 T&A'd 11/3/2014

P&A Wellbore

GL Elevation above MSL: 2,488'



<u>Casing & Cement</u>

***Conductor*:** 13 3/8 OD, @ 80'

***Surface*:** 24 jts, 9-5/8" OD, 8.83 ID,40#, K-55 @ 1,082'

215 Sacks, (144 Bbls) Type III Cement + Slurrylite 50 Pps, 20% MS-500, 5% HW Gypsum, 5% Salt B.W.O.W., 0.75% TSFL-180, 0.25% CFL-300, 3.77 ft3/sk, 14.22 gal/sk, 10.4 ppg. Followed by 70 sacks, (17 Bbbls) Type III Cement + 5% Salt B.W.O.W., 1.36 ft3/sk, 6.42 gal/sk, 14.8 ppg.

<u>Pump Top Job as Follows</u>: Pump 116 sacks (23 Bbls) Calprem Cement + 2% Cacl2, 1.15 ft3/sk, 5 gal/sk, 15.8 ppg. Pump Top out cement @ 1.0 Bpm & 100 psi. (4 Bbls Cement to surface)

***Production*:** 7" OD, 6.276" ID, J-55 @5.500'

Run 122 Total joints of 7", 26# J-55, LTC Casing as follows:

Float Shoe set @ 5,500', 2 Joints of Casing, Float collar set @ 5,406', 120 Joints of casing. Ran 64 Total 7" X 8 1/2" Bow Spring Centralizers, 1- Centralizer 10' above Shoe, 1- Centralizer on 1st casing Collar, 1- Centralizer 10' Below Float Collar, Centralizer on every Joint to Joint # 44 @ 3,509'. Then every 4th Joint to Joint #120 @ 80'. Centralizers Where Installed on collars on Casing Joints. Filled & circulated every 20 joints (No tight hole or problems Running Casing) (Tag with Joint #122 @ 5,500');

<u>Cement as Follows</u>: Pump 10 bbls of Diesel, 25 bbls of 10.0 Ppg Weighted Spacer @ 4.0 Bpm and 250 psi, Followed by 400 Sacks, (129 Bbls) TCI lite 61.6 Pps, Class G Cement, 25.9 Pps Flyash, 5.22 Pps gel, 1.82 ft3/sk, 9.72 gal/sk, 12.7 ppg. Pump Lead cement @ 3 Bpm & 340 psi. Followed by 265 Sacks, (54.7 Bbbls) Gas Seal Cement, Class G Cement, 3% Salt, 0.75% TSFL-180, 0.2% C-49, 1.16 ft3/sk, 4.9 gal/sk, 16.0 ppg. Pump Tail cement @ 3 Bpm & 239 psi. Displace with 208 Total Bbls as Follows: 152 Bbls 4% KCL Water @ 2 Bpm & 1300 Psi, (Lost Returns With 152 Bbls Displacement Away) (No Returns on last 56 Bbls) Pumped last 56 Bbls Displacement @ 1 Bpm & 3,700 Psi. (Bumped plug With 4,200 psi) Bleed off 2.5 Bbls, Check Floats, Floats Held Good. (No Spacer or Cement to Surface)

Pumped 9 cubic yards cement top down surface job.

5,500' TVD

Well Name & No.: DJS Properties 2-14	Field: Willow
County: Payette	State: Idaho
Total Depth (MD): 5,500'	(TVD) 5,500'
Date Completed: T&A on 11/3/2014	

OMB No. 2040-0042 Approval Expires 12/31/2018

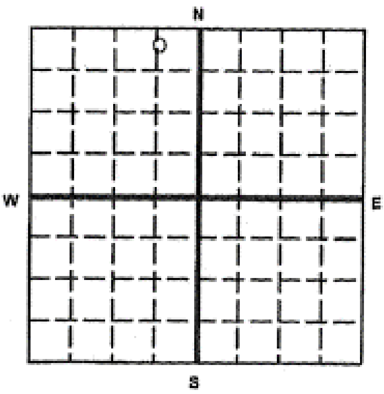
EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
DJS Properties #2-14	Snake River Oil and Gas, LLC, 117 East Calhoun St., Magnolia, AR 71753

Locate Well and Outline Unit on Section Plat - 640 Acres



State	County	Permit Number
Idaho	Payette	LU600120

Surface Location Description

NW 1/4 of NE 1/4 of NE 1/4 of NW 1/4 of Section 14 Township 8N Range 4W

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface Location 95 ft. frm (N/S) N Line of quarter section
and 2315 ft. from (E/W) W Line of quarter section.

TYPE OF AUTHORIZATION

- ☑ Individual Permit
- ☐ Area Permit
- ☐ Rule

Number of Wells 1

Lease Name DJS Properties

WELL ACTIVITY

- ☐ CLASS I
- ☑ CLASS II
  - ☐ Brine Disposal
  - ☐ Enhanced Recovery
  - ☐ Hydrocarbon Storage
- ☐ CLASS III

Well Number 2-14

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
7"	26	5500	5500	8.75"
9.625	40	1062	1062	12.75
13.375"	61	120	120	17.5"

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- ☑ The Balance Method
- ☐ The Dump Bailer Method
- ☐ The Two-Plug Method
- ☑ Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inches)	7"	7"					
Depth to Bottom of Tubing or Drill Pipe (ft)	5410	750					
Sacks of Cement To Be Used (each plug)	TBD	TBD					
Slurry Volume To Be Pumped (cu. ft.)	282	162					
Calculated Top of Plug (ft.)	4100	0					
Measured Top of Plug (if tagged ft.)	N/A	N/A					
Slurry Wt. (Lb./Gal.)	TBD	TBD					
Type Cement or Other Material (Class III)	TBD	TBD					

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
4306	4330 (existing perfs)	5380	5390 existing perfs)
4354	4374 (existing perfs)	5390	5410 (to be added for injection)
5045	5050 (existing perfs)		
5335	5360 (existing perfs)		

Estimated Cost to Plug Wells

TBD - cement type, volumes, density, and type to be determined based on regulatory requirements and products in existence at time of plugging.

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title (Please type or print)	Signature	Date Signed
Richard Brown, Manager	Richard Brown	1-30-2020

EPA Form 7520-14 (Rev. 12-11)

2/27/2020

To: Richard Brown
Snake River Oil and Gas
117 East Calhoun
Magnolia AR 70753

Re: DJS 2-14 Plug

I have enclosed an estimated cost to plug the DJS 2-14.

Cement Crew	$25,000.00
E-LOG Services	$30,000.00
Vacuum Truck Services / Welder	$8,500.00
Disposal Services / Rentals / Location Clean up	$2,500.00

We are looking at an estimated cost of $66,000.00 based on what was required on the past abandonment work.

Please feel free to contact me directly if you have any questions.

Robert Hatfield
(208) 459-9990

HTI Services, LLC. | P.O. Box 709, Star Idaho 83669| Phone: (208) 459-9990 | Fax: (208) 779-3055

TRUST AGREEMENT

TRUST AGREEMENT, the "Agreement," entered into as of February 14, 2020, by and between Snake River Oil & Gas, LLC, An Idaho Limited Liability Company, the "Grantor," and BancorpSouth, incorporated in the state of Mississippi, the "Trustee."

Whereas, the United States Environmental Protection Agency, "EPA," an agency of the United States Government, has established certain regulations applicable to the Grantor, requiring that an owner or operator of an injection well shall provide assurance that funds will be available when needed for plugging and abandonment of the injection well,

Whereas, the Grantor has elected to establish a trust to provide all or part of such financial assurance for the facility(ies) identified herein,

Whereas, the Grantor, acting through its duly authorized officers, has selected the Trustee to be the trustee under this agreement, and the Trustee is willing to act as trustee,

Now, therefore, the Grantor and the Trustee agree as follows:

Section 1. Definitions. As used in this Agreement:

(a) The term "Grantor" means the owner or operator who enters into this Agreement and any successors or assigns of the Grantor.

(b) The term "Trustee" means the Trustee who enters into this Agreement and any successor Trustee.

(c) Facility or activity means any "underground injection well" or any other facility or activity that is subject to regulation under the Underground Injection Control Program.

Section 2. Identification of Facilities and Cost Estimates. This Agreement pertains to the facilities and cost estimates identified on attached Schedule A. (Schedule A lists, for each facility, the EPA identification number, name, address, and the current plugging and abandonment cost estimate, or portions thereof, for which financial assurance is demonstrated.)

Section 3. Establishment of Fund. The Grantor and the Trustee hereby establish a trust fund, the "Fund," for the benefit of EPA. The Grantor and the Trustee intend that no third party have access to the Fund except as herein provided. The Fund is established initially as consisting of the property, which is acceptable to the Trustee, described in Schedule B attached hereto. Such property and any other property subsequently transferred to the Trustee is referred to as the Fund, together with all earnings and profits thereon, less any payments or distributions made by the Trustee pursuant to this Agreement. The Fund shall be held by the Trustee, IN TRUST, as hereinafter provided. The Trustee shall not be responsible nor shall it undertake any responsibility for the amount or adequacy of, nor any duty to collect from the Grantor, any payments necessary to discharge any liabilities of the Grantor established by EPA.

Section 4. Payment for Plugging and Abandonment. The Trustee shall make payments from the Fund as the EPA Regional Administrator shall direct, in writing, to provide for the payment of the costs of plugging and abandonment of the injection wells covered by this Agreement. The Trustee shall reimburse the Grantor or other persons as specified by the EPA Regional Administrator from the Fund for plugging and abandonment expenditures in such amounts as the EPA Regional Administrator shall direct in writing. In addition, the Trustee shall refund to the Grantor such amounts as the EPA Regional Administrator specifies in writing. Upon refund, such funds shall no longer constitute part of the Fund as defined herein.

Section 5. Payments Comprising the Fund. Payments made to the Trustee for the Fund shall consist of cash or securities acceptable to the Trustee.

Section 6. Trustee Management. The Trustee shall invest and reinvest the principal and income of the Fund and keep the Fund invested as a single fund, without distinction between principal and income, in accordance with general investment policies and guidelines which the Grantor may communicate in writing to the Trustee from time to time, subject, however, to the provisions of this Section. In investing, reinvesting, exchanging, selling, and managing the Fund, the Trustee shall discharge his duties with respect to the trust fund solely in the interest of the beneficiary and with the care, skill, prudence, and diligence under the circumstances then prevailing which persons of prudence, acting in a like capacity and familiar with such matters, would use in the conduct of an enterprise of a like character and with like aims; *except that:*

(i) Securities or other obligations of the Grantor, or any other owner or operator of the facilities, or any of their affiliates as defined in the Investment Company Act of 1940, as amended, 15 U.S.C. 80a-2.(a), shall not be acquired or held, unless they are securities or other obligations of the Federal or a State government;

(ii) The Trustee is authorized to invest the Fund in time or demand deposits of the Trustee, to the extent insured by an agency of the Federal or State government; and

(iii) The Trustee is authorized to hold cash awaiting investment or distribution uninvested for a reasonable time and without liability for the payment of interest thereon.

Section 7. Commingling and Investment. The Trustee is expressly authorized in its discretion:

(a) To transfer from time to time any or all of the assets of the Fund to any common, commingled, or collective trust fund created by the Trustee in which the Fund is eligible to participate, subject to all of the provisions thereof, to be commingled with the assets of other trusts participating therein; and

(b) To purchase shares in any investment company registered under the Investment Company Act of 1940, 15 U.S.C. 80a-1 *et seq.*, including one which may be created, managed, underwritten, or to which investment advice is rendered or the shares of which are sold by the Trustee. The Trustee may vote shares in its discretion.

Section 8. Express Powers of Trustee. Without in any way limiting the powers and discretions conferred upon the Trustee by the other provisions of this Agreement or by law, the Trustee is expressly authorized and empowered:

(a) To sell, exchange, convey, transfer, or otherwise dispose of any property held by it, by public or private sale. No person dealing with the Trustee shall be bound to see to the application of the purchase money or to inquire into the validity or expediency of any such sale or other disposition;

(b) To make, execute, acknowledge, and deliver any and all documents of transfer and conveyance and any and all other instruments that may be necessary or appropriate to carry out the powers herein granted;

(c) To register any securities held in the Fund in its own name or in the name of a nominee and to hold any security in bearer form or in book entry, or to combine certificates representing such securities with certificates of the same issue held by the Trustee in other fiduciary capacities, or to deposit or arrange for the deposit of such securities in a qualified central depository even though, when so deposited, such securities may be merged and held in bulk in the name of the nominee of such depositary with other securities deposited therein by another person, or to deposit or arrange for the deposit of any securities issued by the United States Government, or any agency or instrumentality thereof, with a Federal Reserve bank, but the books and records of the Trustee shall at all times show that all such securities are part of the Fund;

(d) To deposit any cash in the Fund in interest-bearing accounts maintained or savings certificates issued by the Trustee, in its separate corporate capacity, or in any other banking institution affiliated with the Trustee, to the extent insured by an agency of the Federal or State government; and

(e) To compromise or otherwise adjust all claims in favor of or against the Fund.

Section 9. Taxes and Expenses. All taxes of any kind that may be assessed or levied against or in respect of the Fund and all brokerage commissions incurred by the Fund shall be paid from the Fund. All other expenses incurred by the Trustee in connection with the administration of this Trust, including fees for legal services rendered to the Trustee, the compensation of the Trustee to the extent not paid directly by the Grantor, and all other proper charges and disbursements of the Trustee shall be paid from the Fund.

Section 10. Annual Valuation. The Trustee shall annually, at least 30 days prior to the anniversary date of establishment of the Fund, furnish to the Grantor and to the appropriate EPA Regional Administrator a statement confirming the value of the Trust. Any securities in the Fund shall be valued at market value as of no more than 60 days prior to the anniversary date of establishment of the Fund. The failure of the Grantor to object in writing to the Trustee within 90 days after the statement has been furnished to the Grantor and the EPA Regional Administrator shall constitute a conclusively binding assent by the Grantor, barring the Grantor from asserting any claim or liability against the Trustee with respect to matters disclosed in the statement.

Section 11. Advice of Counsel. The Trustee may from time to time consult with counsel, who may be counsel to the Grantor, with respect to any question arising as to the construction of this Agreement of any action to be taken hereunder. The Trustee shall be fully protected, to the extent permitted by law, in acting upon the advice of counsel.

Section 12. Trustee Compensation. The Trustee shall be entitled to reasonable compensation for its services as agreed upon in writing from time to time with the Grantor.

Section 13. Successor Trustee. The Trustee may resign or the Grantor may replace the Trustee, but such resignation or replacement shall not be effective until the Grantor has appointed a successor trustee and this successor accepts the appointment. The successor trustee shall have the same powers and duties as those conferred upon the Trustee hereunder. Upon the successor trustee's acceptance of the appointment, the Trustee shall assign, transfer, and pay over to the successor trustee the funds and properties then constituting the Fund. If for any reason the Grantor cannot or does not act in the event of the resignation of the Trustee, the Trustee may apply to a court of competent jurisdiction for the appointment of a successor trustee or for instructions. The successor trustee shall specify the date on which it assumes administration of the trust in a writing sent to the Grantor, the EPA Regional Administrator, and the present Trustee by certified mail 10 days before such change becomes effective. Any expenses incurred by the Trustee as a result of any of the acts contemplated by this Section shall be paid as provided in Section 9.

Section 14. Instructions to the Trustee. All orders, requests, and instructions by the Grantor to the Trustee shall be in writing, signed by such persons as are designated in the attached Exhibit A or such other designees as the Grantor may designate by amendment to Exhibit A. The Trustee shall be fully protected in acting without inquiry in accordance with the Grantor's orders, requests, and instructions. All orders, requests, and instructions by the EPA Regional Administrator to the Trustee shall be in writing, signed by the EPA Regional Administrators of the Regions in which the facilities are located, or their designees, and the Trustee shall act and shall be fully protected in acting in accordance with such orders, requests, and instructions. The Trustee shall have the right to assume, in the absence of written notice to the contrary, that no event constituting a change or a termination of the authority of any person to act on behalf of the Grantor or EPA hereunder has occurred. The Trustee shall have no duty to act in the absence of such orders, requests, and instructions from the Grantor and/or EPA, except as provided for herein.

Section 15. Notice of Nonpayment. The Trustee shall notify the Grantor and the appropriate EPA Regional Administrator, by certified mail within 10 days following the expiration of the 30-day period after the anniversary of the establishment of the Trust, if no payment is received from the Grantor during that period. After the pay-in period is completed, the Trustee shall not be required to send a notice of nonpayment.

Section 16. Amendment of Agreement. This Agreement may be amended by an instrument in writing executed by the Grantor, the Trustee, and the appropriate EPA Regional Administrator, or by the Trustee and the appropriate EPA Regional Administrator if the Grantor ceases to exist.

Section 17. Irrevocability and Termination. Subject to the right of the parties to amend this Agreement as provided in Section 16, this Trust shall be irrevocable and shall continue until terminated at the written agreement of the Grantor, the Trustee, and the EPA Regional Administrator, or by the Trustee and the EPA Regional Administrator if the Grantor ceases to exist. Upon termination of the Trust, all remaining trust property, less final trust administration expenses, shall be delivered to the Grantor.

Section 18. Immunity and Indemnification. The Trustee shall not incur personal liability of any nature in connection with any act or omission, made in good faith, in the administration of this Trust, or in carrying out any directions by the Grantor or the EPA Regional Administrator issued in accordance with this Agreement. The Trustee shall be indemnified and saved harmless by the Grantor or from the Trust Fund, or both, from and against any personal liability to which the Trustee may be subjected by reason of any act or conduct in its official capacity, including all expenses reasonably incurred in its defense in the event the Grantor fails to provide such defense.

Section 19. Choice of Law. This Agreement shall be administered, construed, and enforced according to the laws of the State of Mississippi.

Section 20. Interpretation. As used in this Agreement, words in the singular include the plural and words in the plural include the singular. The descriptive headings for each Section of this Agreement shall not affect the interpretation or the legal efficacy of this Agreement.

In Witness Whereof the parties have caused this Agreement to be executed by their respective officers duly authorized and their corporate seals to be hereunto affixed and attested as of the date first above written. The parties below certify that the wording of this Agreement is identical to the wording specified in 40 CFR 144.70(a)(1) as such regulations were constituted on the date first above written.

Signature of Grantor

By: SNAKE RIVER OIL & GAS, LLC

Attest: ______________________

Chris Weiser

Title: Managing Member

By: BANCORPSOUTH

Attest: Ron Mills ______________________

Ron Mills

Title: Senior Vice President & Regional Trust Manager

Certificate of Acknowledgement
For
Standby Trust Agreement

STATE OF ARKANSAS)
)ss.
COUNTY OF COLUMBIA)

On this 14th day of February, 2020, before me personally appeared Chris Weiser, to me known, who, being duly sworn, did depose and say that Snake River Oil & Gas, LLC, conducts business at 117 East Calhoun, P.O. Box 500, Magnolia, Arkansas 71754-0500, that he is the Managing Member of Snake River Oil & Gas, LLC, a Limited Liability Company, described in and which executed the above instrument, and that he signed his name thereto by like order.

Royce Dixon
Notary Public, Nevada County, Arkansas

My commission expires: 6/2/2021

STATE OF TEXAS)
)ss.
COUNTY OF BOWIE)

On this 28th day of February, 2020, before me personally appared Ronald Mills, to me known, who, being duly sworn, did depose and say that BANCORP SOUTH BANK conducts business at 5702 Richmond Road, Texarkana, TX 75503-0501, that he is the ~~President of~~ Senior VP & Trust Officer, the Bank described in and which executed the above instrument, and that he signed his name thereto by like order.

AILEEN DOSSEY
Notary Public
STATE OF TEXAS
ID#249127-1
My Comm. Exp. Feb. 10, 2021

Aileen Dossey
Notary Public, Bowie County, Texas

My commission expires: 2/10/2021

SCHEDULE A

Identification of Facilities and Cost Estimates

Schedule A is referenced in the trust agreement dated February 14, 2020

by and between Snake River Oil and Gas, LLC,

the "Grantor" and Bancorp South, Inc.,

the "Trustee."

EPA identification number	ID-2D001-A
Name of facility	DJS #2-14
Address of facility	Section 14-Township 8 North-Range 4 West Boise, Meredian, Payette County Idaho
Current plugging and Abandonment cost estimate	$ 66,000
Date of estimate	2/27/2020

EPA identification number	
Name of facility	
Address of facility	
Current plugging and Abandonment cost estimate	
Date of estimate	

SCHEDULE B

Establishment of Fund

That certain Irrevocable Standby Letter of Credit No. (b) (6), in the amount of $100,000.00, dated 2/20/2020, by and between BancorpSouth, Inc. and Snake River Oil and Gas, LLC.

BancorpSouth

FILE COPY

Chris Hladick, Regional Administrator, Region 10
U.S. Environmental Protection Agency
1200 Sixth Avenue, Suite 155
Seattle, WA 98101

RE: DJS#2-14
Section 14-T8N-R4W
Boise Meridian
Payette County, Idaho

Dear Sir or Madam:

We hereby establish our Irrevocable Standby Letter of Credit No. (b) (6) [redacted] in your favor, at the request and for the account of Snake River Oil and Gas, LLC at 117 Calhoun Street, Magnolia, AR 71753 up to the aggregate amount of One Hundred Thousand U.S. Dollars $100,000.00, available upon presentation of:

1. Your sight draft, bearing reference to this Irrevocable Standby Letter of Credit No. 545001016266, and

2. Your signed statement reading as follows: "I certify that the amount of the draft is payable pursuant to regulations issued under authority of the Safe Drinking Water Act."

This Letter of Credit is effective as of February 14, 2020 and shall expire on February 14, 2021, but such expiration date shall be automatically extended for a period of 1 year on February 14, 2021 and on each successive expiration date, unless, at least 120 days before the current expiration date, we notify both you and Snake River Oil and Gas, LLC by certified mail that we have decided not to extend this letter of credit beyond the current expiration date. In the event you are so notified, any unused portion of the credit shall be available upon presentation of your sight draft for 120 days after the date of receipt by both you and Snake River Oil and Gas, LLC, as shown on the signed return receipts.

Whenever this letter of credit is drawn on under and in compliance with the terms of this credit, we shall duly honor such draft upon presentation to us, and we shall deposit the amount of the draft directly into the standby trust fund of Snake River Oil and Gas, LLC in accordance with your instructions.

We certify that the wording of this letter of credit is identical to the wording specified in 40 CR 144.70(d) as such regulations were constituted on the date shown immediately below.

P.O. Box 789, Tupelo, MS 38802 | 2778 West Jackson Street, Building C, Tupelo, MS 38801 | P: 662-680-2000 | F: 662-620-4325

BANCORPSOUTH BANK

BY: Heather M. Sullivan

Heather M. Sullivan

ITS: Vice President

DATE: 2/14/20

This credit is subject to the Uniform Customs and Practice for Documentary Credits published and copyrighted by the International Chamber of Commerce Brochure No. 600 (2007 Revision).

Page 2 of 2

ATTACHMENT S: Aquifer Exemption Request

Attachment S is submitted as a separately bound volume with appendices. A digital copy of the Attachment S - Aquifer Exemption Request, is available in the digital folders file.

ATTACHMENT T: Existing EPA Permits

Applicant Snake River Oil and Gas, LLC does not hold any existing EPA Permits.

ATTACHMENT U: Description of Business

U. Description of Business – Snake River Oil and Gas LLC is the Idaho operating subsidiary of Weiser-Brown Oil Company out of Magnolia AR. Both Weiser-Brown Oil Company and Snake River Oil and Gas are owned 50/50 by the Weiser Family and Brown Family Ltd Partnerships. The Weisers and Browns involvement in the oil and gas industry spans generations and began in 1955. Snake River is managed by the founder's sons Richard Brown and Chris Weiser. Snake River Oil and Gas was founded specifically in 2011 to explore and develop natural gas deposits in Western Idaho.